

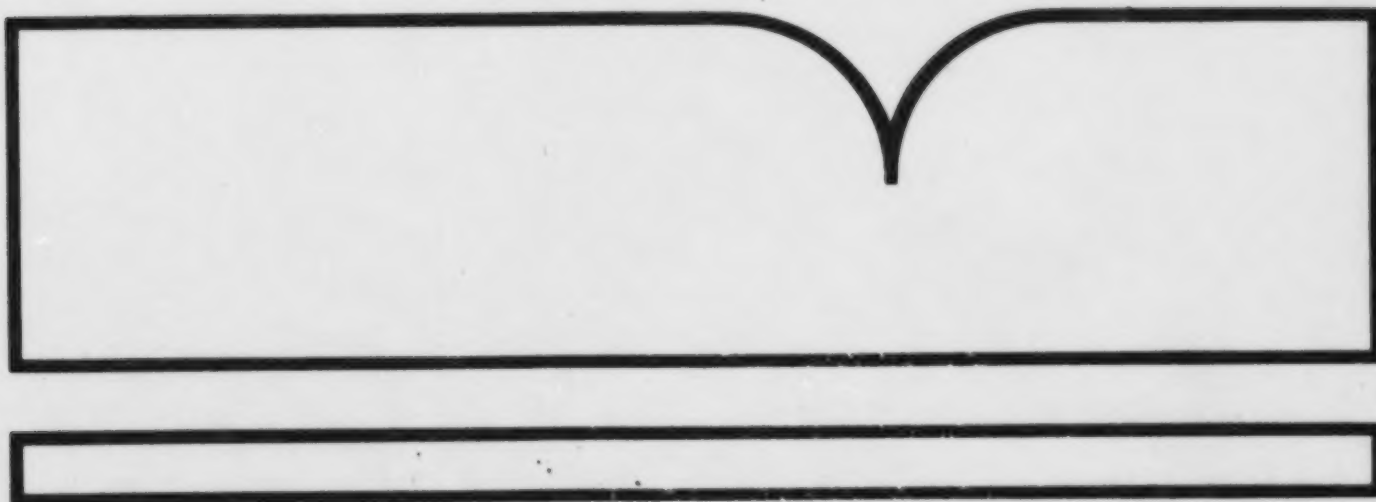
Proceedings of the 1982 Joint Symposium on
Stationary Combustion NO_x Control
Volume 1. Utility Boiler Applications

Acurex Corp., Mountain View, CA

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PROCEEDINGS OF THE 1982 JOINT SYMPOSIUM
ON STATIONARY COMBUSTION NO_x CONTROL

Volume I

Utility Boiler Applications

Symposium Cochairmen

Robert E. Hall and Dennis C. Drechsel, EPA
and
Michael W. McElroy, EPRI

Air and Energy Engineering Research Laboratory
Office of Research and Development
U.S. Environmental Protection Agency
Research Triangle Park, NC 27711

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PREFACE

The 1982 Joint Symposium on Stationary Combustion NO_x Control was held November 1 through 4 in Dallas, Texas. This was the second symposium on NO_x control jointly sponsored by EPA and EPRI; the first was held in Denver in 1980. The symposium is a consolidation of EPRI's previous NO_x Control Technology Seminars and EPA's Symposia on Stationary Source Combustion. The objective of the symposium is to give attendees the opportunity to exchange information on the latest advances in combustion technology. Such an exchange of information contributes significantly to the development of cost-effective and reliable NO_x control systems.

Over 50 papers* were presented, beginning with an update of NO_x regulatory trends; focusing on development of control technology for coal-fired utility boilers, industrial power equipment, and process heaters; and discussing advances in fundamental combustion research. Speakers represented a wide variety of organizations including electric utility companies, manufacturers of utility boilers and process equipment, research and development groups conducting investigations sponsored by EPRI and EPA, as well as staff members of EPRI and EPA. Representatives from Japanese and West German utilities and boiler manufacturers provided status reports of activities in those countries, lending an international perspective to NO_x control issues.

Cochairmen of the symposium were Robert E. Hall and Dennis C. Drehmel of EPA, and Michael W. McElroy of EPRI. Introductory remarks were delivered by Robert C. Carr, program manager in the Air Quality Control Program of EPRI's Coal Combustion Systems Division, and the welcoming address was given by Frances Phillips, Deputy Regional Administrator for EPA Region VI. The Symposium Proceedings has been published in two volumes:

Volume I -- UTILITY BOILER APPLICATIONS

- Session I: NO_x Emissions Issues
- Session II: Manufacturer's Update of Commercially Available Combustion Technology
- Session III: Operational and Environmental Issues
- Session IV: Low-NO_x Combustion Development
- Session V: In-Furnace NO_x Destruction (Reburning)
- Session VI: Furnace Limestone Injection

Volume II -- FLUE GAS TREATMENT, FUNDAMENTAL STUDIES AND INDUSTRIAL/COMMERCIAL/RESIDENTIAL APPLICATIONS

- Session VII: Flue Gas Treatment
- Session VIII: Fundamental Combustion Studies
- Session IX: Stationary Engines and Industrial Process Systems
- Session X: Small Industrial, Commercial, and Residential Systems

*Portions of the work described in these proceedings were not funded by the U. S. Environmental Protection Agency; therefore, the contents do not necessarily reflect the views of the Agency and no official endorsement should be inferred.

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INTRODUCTORY REMARKS

By:

Robert C. Carr
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On behalf of the Electric Power Research Institute, I would like to welcome everyone to Dallas for the second symposium and just make a few general comments on NO_x.

The EPRI perspective on this particular symposium is that it's certainly the most prestigious and most important symposium that relates to NO_x control in the industry. I think we have a unique conference. We have a very international flavor here. We have attendees from Japan, Germany, Canada, the Netherlands, France, and, of course, from all over the United States. This meeting brings together all the important people in NO_x control -- the users (utilities and other industries), the research specialists, the regulatory people, as well as the manufacturers. That's what makes this conference unique and allows us to exchange meaningful information.

The issue of NO_x control has been with us (when I say "us," I mean the industry and regulatory people) for some time. However, there are several issues that are now appearing on the horizon that promise to increase the pressure for broader NO_x control across the United States and, therefore, are accelerating the need for effective NO_x emissions control. The general category of concern is atmospheric loading of pollutants. The most potent example of that is acid precipitation or acid rain. Other concerns are atmospheric visibility, secondary particulate formation in the atmosphere, oxidants, and long-range transport. All of these may in fact require some form of NO_x control or NO_x may be implicated. With respect to the acid precipitation issue, this is perhaps the latest and certainly the most politically potent issue to face the utility industry because it may mean expanded retrofit NO_x emissions controls, particularly for the large coal-fired power plant population that we have. Although the role that NO_x would play in the acid rain legislation is not clear at this time, I think it is important that we clearly understand the options we have and anticipate the worst.

As a result of all these issues, a growing importance is being placed on NO_x control in the utility industry and in other industries as well. For most utilities, retrofit of coal-fired power plants for NO_x control is the major concern right now. There are fewer and fewer plants being constructed, and we don't anticipate any large growth of power plant construction in this decade. So most of the activity will be directed toward existing plants.

Since the last symposium, there have been some significant developments in the NO_x technology area such as combustion NO_x control via in-furnace destruction or reburning, continuing development of flue gas treatment (particularly in Japan), and furnace limestone injection for combined NO_x/SO₂ control. Many of these advancements are being spearheaded by the Japanese, who are clearly leaders in the NO_x area.

With respect to the electric utility industry, there are several concerns that must be addressed in NO_x control, many of which will be discussed at this meeting. I would like to make a few remarks about my perspective, and Charles Goodman from Southern Company Services will give a paper later this morning that will offer a more in-depth view of the utility perspective.

First, whatever we use, we want it to be simple, cheap, and reliable. I think the item of cost is particularly sensitive to the utility industry. It is due to the high cost of money and the long lead times required to build anything new. The utilities have a restricted capital investment capability currently which is very serious. It is difficult to raise front-end money for any new construction. Accordingly, the combustion control option for NO_x is the preferred one because of its simplicity and low cost, and because of the high NO_x removals we think we can achieve. Although the postcombustion control option does offer the potential of low NO_x, it also offers the certainty of high cost and perhaps even some reliability problems in the back end of the boiler. We think that the cost benefit of this option must be carefully weighed against incremental benefit in NO_x removals that may result. It is unclear at this time that the cost of postcombustion NO_x control justifies the incremental benefit.

Another area that is clearly important: you can't jeopardize operation of the boiler or the reliability of the steam generator. After all, this is the heart of the plant, and we don't want to make it any more complicated than it already is.

On the subject of cost, we think it is also important to combine environmental control technologies whenever you can. Adding a black box for every new pollutant species is very simple in concept, very expensive in practicality, and certainly not very creative. We think it is important whenever possible to combine processes; once again, to save the capital and also save operation and maintenance costs. I think the furnace limestone injection process (if it can be made to work and achieve the levels of SO₂ control we need) is certainly a candidate process that deserves a concerted amount of effort right now.

EPRI has the support of our utility advisory structure to pursue a vigorous NO_x R&D program, particularly in the retrofit area. Despite the uncertainties in the regulatory area, which we will hear about later, we are certainly supporting a major R&D effort in the development of retrofit NO_x controls for existing coal-fired power plants. Also, we are currently performing proof-of-concept work in the limestone injection area, and assuming that looks good, we anticipate a more comprehensive limestone injection program next year.

From my personal perspective, I would like to add a few other comments. I think we all recognize the importance of NO_x control in the utility industry. Of the three emissions we are trying to control -- particulate matter, SO₂, and NO_x -- I personally think that NO_x is the most difficult and most complicated. We have a reasonably good handle on particulate matter control now, and we are doing reasonably well with SO₂. I think NO_x in the future is going to be a big issue, and I don't think we are as far along as we would like to be. One of the reasons is that if you are going to control NO_x, you are talking about getting intimately involved with the processes occurring in the furnace: the fluid dynamics, thermodynamics, heat transfer, and chemistry. This makes it very difficult to scale up anything you do at a small scale, which is why I think NO_x control is more difficult than any of the other technologies we are dealing with. And the implications of a premature commercialization are extremely severe since we are dealing with the heart of the plant -- the boiler. I think these complexities are exemplified by the fact that in particulate matter we are pretty confident we can achieve 99.9 percent removals with new technologies. With SO₂ we are talking about 90 percent, and with NO_x we are talking about 80 percent.

The papers we are going to hear today and the rest of the week will demonstrate that we are making significant progress in NO_x control. The meeting agenda is divided into several distinct areas. We will hear updates of topics we have discussed before such as the status of regulations, combustion controls that are currently in place, and experience with flue gas treatment. We will also hear about some important new work: furnace limestone injection and in-furnace NO_x destruction or reburning. And there will be several papers describing fundamental combustion studies. I would like to emphasize the importance of the fundamental work. I think that this is where the new ideas and future developments are going to come from. Indeed the topics that are new sessions this time -- limestone injection and reburning -- were actually introduced in the fundamental sessions a few years ago. If you don't understand the fundamentals, it is a very difficult process to scale up and develop anything that is going to have widespread utilization.

With those remarks, I would like to close by again welcoming everybody. I am looking forward to an excellent symposium.

CLOSING REMARKS

By:

Dennis C. Drehmel
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Research Triangle Park, North Carolina 27711

This symposium dealt with NO_x control for stationary sources including power plants, process heaters, cement kilns, wood stoves, and industrial boilers. In addition, SO_x control was considered in conjunction with low- NO_x systems for utility and stoker boilers. For power plants, low- NO_x technology may be derived from new burner design or firing systems and from flue gas treatment. Concomitant SO_x control is achievable in the furnace with sorbent injection or downstream of the furnace with flue gas treatment. Presentations by boiler manufacturers confirmed that each had currently available burner and/or firing systems to achieve at least a 40 to 60 percent reduction in NO_x from levels before the advent of the New Source Performance Standards (NSPS). Some examples of these are the controlled combustion venturi burner, the controlled flow/split flame burner, the controlled mixing burner, and the low- NO_x concentric firing system. In addition, Southern California Edison reported on a fuel staging system called the ICNF (in-furnace control of NO_x formation) which reduced NO_x from 400 to as low as 130 ppm at the Alamedas No. 2 power plant. Other systems under development include the MHI series PM burner, the distributed mixing burner (DMB), the Foster Wheeler fuel-staged burner, the Babcock & Wilcox primary combustion furnace, and the MACT (Mitsubishi Advanced Combustion Technology).

The PM burner is an improvement in tangentially fired furnaces using a new arrangement of fuel, air, and flue gas recirculation ports. The idea is to introduce a concentrated fuel stream between two streams of recirculated flue gas to delay burning and provide a reducing atmosphere to convert fuel nitrogen to N_2 . The DMB reduces NO_x also by establishing a fuel-rich region. This is accomplished in a wall-fired furnace by introducing less than theoretical air with the individual burners and the balance of the air through tertiary ports between the burners. The MACT, developed for tangential corner-fired furnaces, also uses a reducing zone, but in this case the zone is provided by firing a minority fraction of the fuel considerably above the main firing zone. As the NO_x formed in the main firing zone rises through the second burning zone it is reduced to N_2 . Both PM burners and MACT allow lowering of stack NO_x to levels which are a 75 to 85 percent

reduction from pre-NSPS levels. Incremental cost for a new application of PM burners was reported to be less than \$5/kW.

Flue gas treatment for NO_x control included selective catalytic reduction (SCR), thermal deNO_x , and dry NO_x/SO_x control processes. The latter consists of carbon adsorption processes, electron beam irradiation processes, and copper oxide processes. Control efficiencies of NO_x in flue gas treatment processes are generally 90 percent, except for thermal deNO_x where 50 to 65 percent is typical. Reported costs of control were: SCR (Hitachi-Zosen), \$53 to \$95/kW; thermal deNO_x (Exxon), \$40/kW; carbon adsorption (Mitsui), \$117/kW; electron beam (Avco-Ebara), \$333/kW; copper oxide (Shell), \$238/kW. Unfortunately, these costs are not exactly comparable because of differing assumptions and the fact that the latter three are also controlling 90 percent of the sulfur dioxide.

Control of SO_x is also possible by adding sorbent to the coal or by injection into the furnace. The former method is used by RWE (Rheinisch-Westfälisches Elektrizitätswerk) in tests burning brown coal. Brown coals range from 40 to 70 percent in moisture and hence produce a peak flame temperature of only $1,200^\circ\text{C}$. Under this condition, calcium hydroxide is an effective sorbent for SO_x when introduced with the coal. Information on the limestone injection method comes from work in Europe sponsored by Steinmuller and from work in the U.S. sponsored by EPA. In both, the percentage SO_x controlled increased with increasing fuel sulfur and with increasing sorbent addition rate. In both, the sorbent type and the fuel type were important, but the ranking differed. Differences appear to be dependent on the interaction of the furnace time/temperature profile and the inherent nature of the sorbent to develop surface area for reaction as it is initially exposed to temperature. It was reported that limes with extremely high surface areas (as much as $50 \text{ m}^2/\text{g}$) can be produced under the right time/temperature conditions and that the surface area will have a very strong influence on reactivity. The cost of SO_x control by means of sorbent injection at twice the theoretical addition rate was reported to be \$21/kW.

Low- NO_x technology for other stationary sources parallels that for power plants. For process heaters, for example, the use of staged air was reported to reduce NO_x emissions by 60 to 71 percent. Similarly for enhanced oil recovery steam generators, the use of staged air allows operation with acceptable smoke and CO levels while limiting NO_x to below 85 ppm (at 3 percent O_2). For gas-fired firetube boilers, low- NO_x emissions have been achieved by ignition of premixed gas and air on a ceramic fiber matrix. Full load efficiency was 82.6 percent while NO_x emissions were lowered by 77 percent. Control of stationary engines was tested using exhaust gas recirculation, water/oil emulsions, stratified charge, and changed timing. NO_x could be reduced up to 50 percent by exhaust gas recirculation and up to 60 percent by the use of emulsions.

VOLUME I

UTILITY BOILER APPLICATIONS

SESSION I

NO_x EMISSIONS ISSUES
Chairman, Joshua S. Bowen
EPA, IERL/RTP

UPDATE ON NO_x RELATED REGULATIONS

By:

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ABSTRACT

The Clean Air Act and its subsequent amendments through August 1977 provides for both an air quality management and technological based approach to the control of air pollution sources in the United States. The key to the air quality management approach is the Federal government's responsibility to develop national ambient air quality standards. The level of these standards dictate State action in developing plans to control significant sources. An important adjunct to the management approach is the technology based performance standards for new industrial and mobile sources.

This paper will update the status of significant NO₂/NO_x regulatory actions. Since many of these actions are ongoing as this abstract is being written, it may well be that the final presentation will include or exclude some of the proposed discussion items. Items that will be covered include:

- The current review of the national ambient air quality standard for NO₂ which is presently an annual standard at 100 micrograms per cubic meter (.053 ppm). The ongoing review has looked at the possibility of a short-term NO₂ standard.
- A review of new source performance standards for stationary sources.
- Mobile source regulations for NO₂.
- Prevention of significant deterioration regulations and new source review requirements.
- Implementing new monitoring requirements for NO₂.

The basis for the Air Program in the United States is the Clean Air Act and its Amendments which are administered by the Federal Environmental Protection Agency (EPA). The goals of this law are implemented primarily by individual air pollution control agencies in each State, which operate under the guidance of the Federal EPA and under the authority of State laws and regulations.

The Clean Air Act contains two separate but complementary philosophies or strategies for control of air pollutants such as NO_x.

The first strategy can be called air quality management. Its objective is to ensure that ambient air quality does not jeopardize the public health or welfare in any area of the Nation. Under this strategy, our resources are focused on existing pollution sources in heavily polluted areas which are now violating, or are close to violating, the national ambient air quality standards. This air quality management strategy is our primary method for solving current problems.

The second strategy utilizes the technology approach. Its objective is to ensure that all new sources of pollution--both mobile and stationary--install the best available controls at the time they are built regardless of their location. This strategy recognizes that it is usually less expensive to install controls during construction than to retrofit and permit more room for concentrated economic growth before air quality becomes a constraint. Under this strategy, our resources are focused on all new quality problem at the current time. The new source emission standard strategy is used to help ensure that future problems do not develop although, in the case of mobile source control, it is also useful in solving current existing problems.

APPLICATION OF THE AIR QUALITY MANAGEMENT STRATEGY

At this time, a single national ambient air quality standard (NAAQS) (slide 1) has been established for NO₂ at 100 micrograms per cubic meter annual average, which is intended to protect public health and welfare with an adequate margin of safety. The most recent revision to the Clean Air Act requires that each ambient standard be reviewed and modified as necessary every five years. The NO₂ standard is currently under review, and a final decision on the need for modification has not yet been made. EPA staff's conclusions that an annual standard in the range of 100-150 micrograms per cubic meter would be adequate to protect against effects of NO₂ have been concurred on by the Clean Air Scientific Advisory Committee. Staff recommendations will probably be that the present standard be reaffirmed. Proposal of the NO₂ decision could be early in the 1983.

The ozone ambient standard has undergone review and revisions were promulgated in 1979. The next review for the ozone NAAQS has begun and preparation of a new criteria document is underway.

It is anticipated that revision to the carbon monoxide (CO) NAAQS will be promulgated early in 1983. The standards under consideration include a range of levels from about the current level (9 ppm) up to about 12 ppm. The Agency also is carefully examining the potential of using a multiple exceedance standard.

The staff paper for particulate matter has been reviewed by CASAC and work on developing the regulatory package is underway. CASAC has recommended a 10 micron cut off size for a health related standard, and has indicated that both a 24-hour standard and an annual standard are needed. Furthermore, CASAC supported the staff conclusion that the 24-hour concentrations of concern are between 150 and 350 micrograms per cubic meter, and the annual concentrations of concern are between 55 and 110 micrograms per cubic meter (based on the 10 micron cut off size). In both cases, CASAC has indicated that the upper end of the above ranges will provide little or no margin of safety. Proposal is currently scheduled for mid-1983.

The staff paper for sulfur dioxide (SO₂) has undergone an initial review by CASAC and a second draft will be reviewed by CASAC in late August 1982. The major new finding for SO₂ is the potential need for a 1-hour standard to protect asthmatics. Work is currently underway to determine the probability of asthmatics being exposed to SO₂ in the ambient air which could trigger an attack. Proposal is currently scheduled for late 1983.

The review of the hydrocarbon (HC) NAAQS is nearly complete and it is anticipated that the HC standard will be rescinded. This standard was always intended as a guideline only in helping to meet the photochemical oxidant standard. More sophisticated techniques are now available for designing ozone control strategies and the current HC standard is no longer necessary or appropriate for this purpose. Proposal is currently scheduled for early 1983. (the hydrocarbon standard was revoked January 5, 1983)

The review of the lead NAAQS has recently begun and initial work on preparing the criteria document is underway. It is anticipated that the first draft on this document will be available late in 1983 and that any needed revisions to the lead NAAQS will be proposed in early 1984.

AIR QUALITY AND EMISSIONS TRENDS

The current ambient standard for NO₂ is being attained throughout the Nation except in a few metropolitan areas of California--areas which are characterized by fairly heavy industrialization, rapid population growth with correspondingly high motor vehicle traffic, and adverse meteorological conditions which are conducive to formation of NO₂ and which result in very

poor dispersion of all pollutants. Throughout the rest of the Country, no violations of the annual ambient standard were recorded last year, although in previous years minor violations have been recorded in several of our largest cities such as Chicago and Denver.

Generally, ambient NO_2 in the urban areas of the Nation has remained fairly stable for the last decade at levels which average approximately 50 micrograms per cubic meter. Some cities have shown slight deterioration over the years, which others have shown slight improvement. This stable air quality trend is largely due to the fact that improved emission controls on automobiles have been able to compensate for the impact of population and industrial growth in the cities. We expect that this situation will continue for at least the next decade.

Despite the fact that urban NO_2 air quality has remained satisfactory and stable, nationwide emissions of NO_x have been gradually increasing for many years. This increase is primarily attributed to the increased fuel combustion associated with the economic growth of the Nation. Fortunately, the increase in total nationwide emissions has not caused deterioration of urban air quality. This is because the urban air quality is dominated by motor vehicle emissions which are effectively controlled, whereas the total nationwide emissions are dominated by fuel combustion in stationary sources--primarily electrical power plants--which tend to locate in rural areas away from the major population centers.

Our increasing demands for electrical power, and our national policy to rely more heavily on coal, would result in further increases in rural NO_x emissions. However, as will be noted later, control technology on new sources will substantially mitigate the increased NO_x emissions which we would project in the absence of such a provision.

In order to correct past problems associated with ambient air quality monitoring across the United States, EPA promulgated air quality monitoring regulations on May 10, 1979. Since promulgation, overall monitoring activities have been improved significantly. The States have established a network of stations to monitor pollutants to which national ambient air quality standards apply. State and local air monitoring stations (SLAMS) are designed to assist States in meeting their State Implementation Plan (SIP) requirements. National Air Monitoring System (NAMS), a subset of SLAMS, emphasize urban and multi-source areas. By the end of 1981, almost 5,400 SLAMS and 1,400 NAMS were operational. For NO_2 specifically, the criteria requires 2 NAMS monitors be designated in each city of one million population regardless of pollution levels. There are about 490 NO_2 SLAMS monitors in the Nation of which about 55 have been designated as NAMS.

APPLICATION OF THE TECHNOLOGY-BASED STRATEGY

The development of emissions standards for new sources is complicated by two factors. The first factor is the uncertain priority which should be given to emission standards for new sources of NO_x relative to the priority given to other environmental concerns. NO_x is known to be associated with acid deposition, visibility, fine particles, and ozone, but the degree and importance of that association is still subject to considerable uncertainty. The second factor is the difficulty and expense of controlling NO_x emissions at this time, since much of the more promising technology is still in the research and development phase.

There is currently no national emission standard programs oriented specifically toward mitigating the impact of NO_x emission on acid deposition, regional visibility, secondarily formed pollutants, or ozone, although several States are developing regulatory programs to address some of these concerns. We do have a multi-year, multi-million dollar research program underway to investigate the causes and effects of acid deposition, and have entered into formal negotiations with the Government of Canada concerning acid deposition in both our countries. You will hear about this research program from Dr. Demerjian. Research on causes of visibility deterioration and the impact of secondarily formed pollutants on public health and welfare is also being conducted.

We believe that an aggressive regulatory program to control acid deposition, regional visibility, and secondarily formed pollutants at this time would be premature, and that a better understanding of these problems is necessary before specific regulatory programs can be designed. However, revisions to the Clean Air Act are being debated by our Congress this year, and a clear consensus on the relative advantages of immediate regulatory action as opposed to developing a better understanding of the problems has not yet become apparent within the Congress.

The current regulatory program for ozone emphasizes controls on emissions of volatile organic compounds. Although emissions of NO_x influence the atmospheric formation of ozone, the atmospheres of most U.S. cities contain ratios of organic compounds and NO_x such that NO_x controls would have much less impact than organic compound controls on ambient levels of ozone.

EMISSION CONTROLS FOR NEW STATIONARY SOURCES

We have established national emission standards for nitric acid plants, very large fuel combustion sources such as power plants, and gas turbine engines. We are in the process of developing standards for industrial boilers. NO_x from industrial boilers ranks second only to utility boiler emissions.

No decision has been reached by EPA management on industrial boilers. The staff recommended actions were presented to the National Air Pollution Control Techniques Advisory Committee (NAPCTAC) in June 1982. The following four slides were taken from the NAPCTAC presentation:

Slide 2: Scope of Standards

Slide 3: Recommended Standards

Slide 4: Benefit of Standards

All NSPS are to be reviewed every four years or as appropriate. We are just now undertaking a review of the stationary gas turbine engines which will be complete in late 1983.

EMISSION CONTROLS FOR NEW MOBILE SOURCES

Effective with the 1981 model year, the applicable standard for HC automotive exhaust emissions are 0.41 HC, 3.4 gpm CO, and 1.0 gpm NO_x. This was the first year in which the standards mandated by the Clean Air Act Amendments of 1977 took effect. Achievement of these standards was made possible by the development of sophisticated technology (most notably the three-way catalyst) capable of controlling emissions of HC, CO, and NO_x simultaneously.

Similar considerations are applicable to the NO_x standard. The air quality situation is such that only one area of the country that is exceeding the ambient air quality standard for NO_x would benefit from the 1.0 gpm standard. (Other areas with air quality problems are in California, which has its own emission standards for NO_x). Given the costs associated with meeting the NO_x standard of 1.0 gpm and the minimal benefit that will be derived from it, the Administration has recommended that the standard be changed to 2.0 gpm for the immediate future.

EPA recently presented an advanced notice of proposed rulemaking that would set a .25 grams/brake HP-hr particulate for heavy duty diesel engines and a 4 gram/brake HP-hr NO_x standard for both diesel and gasoline engines. These standards would be proposed in mid-1983 and take effect in 1987 or 1988.

Average auto emissions of NO_x have been reduced from 3.7 grams/mile in 1970 to 2.9 grams/mile in 1980 and, even with the adjustment recommended, we expect to see continued reduction in average auto emissions through at least 1990.

PSD REGULATIONS FOR NO₂

PSD regulations were initially promulgated in 1974 in response to a court ruling that EPA was required to establish programs to protect ambient air quality that is cleaner than the NAAQS. The requirements for PSD programs

was explicitly provided by the CAA of 1977. Current PSD regulations are based on allowable incremental increases in ambient concentrations of SO₂ and particulate matter (Set I pollutants) that are specified according to an area classification system.

The CAA of 1977 (Section 166) requires EPA to establish PSD regulations for Set II pollutants (NO_x, HC, O₃, and Pb), but does not restrict the format to an allowable increment system as in the current PSD regulations for SO₂ and particulate matter. A number of alternative PSD approaches have been considered for Set II pollutants. EPA selected the following five options for further study in three regions of the country, each of which is expected to have different levels (high, moderate, and low) of impact from such PSD regulations:

1. Emission controls only
2. Emission controls and emission density zoning
3. Emission controls and inventory management
4. Emission controls and ambient air quality increments for stationary sources, and emission controls and emission inventory management for area sources.
5. Emission controls and transportation-related best available control technology (BACT).

No decision has been made as to the form of the potential PSD regulations.

RESEARCH

We have made extensive research investments in the development of low nitrogen oxides burners and other NO_x control measures, and we anticipate that this research investment will be advanced to the stage of wide-spread national application within the next few years. During the interim period, until the scientific data and engineering designs are fully developed, each new major fuel combustion source is being individually reviewed to determine if the emerging technology and operating procedures can be applied. We anticipate that, eventually, the results of our research investments will pay off and we will be able to establish additional national emission standards which will substantially reduce the total nationwide emissions of NO_x in the United States.

SUMMARY

We believe that our current NO₂ problem in most areas is minimal, and we expect it to remain that way for the foreseeable future. The scientific knowledge of NO_x contributions to acid deposition, atmospheric visibility, secondarily formed pollutants, and ozone is still inadequate to justify implementation of additional aggressive NO_x control programs solely for these purposes. Extensive research on these subjects is directed toward developing new methods for reducing emissions of NO_x. These efforts are already beginning to produce results, and policies and control programs will be tailored to take full advantage of those results when they become available.

SLIDE 1. NATIONAL AMBIENT AIR QUALITY STANDARDS

Pollutant	Primary Standards	Averaging Time	Secondary Standards
Carbon Monoxide	10 mg/m ³ 40 mg/m ³	8-hour ^a 1-hour ^a	Same as primary
Lead	1.5 µg/m ³	Quarterly average	Same as primary
Nitrogen oxides	100 µg/m ³	Annual (arithmetic mean)	Same as primary
Particulate Matter (TSP)	75 µg/m ³ 260 µg/m ³	Annual (geometric mean) 24-hour ^a	60 µg/m ³ ^b 150 µm ³
Ozone	235 µg/ ³	1-hour ^c	Same as primary
Sulfur oxides	80 µg/m ³ 365 µg/m ³ ---	Annual (arithmetic mean) 24-hour ^a 3-hour ^a	--- --- 1300 µg/m ³

^aNot to be exceeded more than once per year.

^bGuide to achieving the 24-hour standard.

^cThe standard is attained when the expected number of days per calendar year with maximum hourly average concentrations above 235 µg/m³ is equal to or less than 1.

SLIDE 2. SCOPE OF STANDARDS

- SIZE >100 MBH HEAT INPUT CAPACITY
- FUEL COMBUSTED COAL, WOOD, SOLID WASTE
- CAPACITY UTILIZATION >30 PERCENT OF POTENTIAL
ANNUAL HEAT INPUT
(8760 HRS X CAPACITY)

SLIDE 3. RECOMMENDED NO_x STANDARDS

<u>FUEL AND BOILER TYPE</u>	<u>NO_x EMISSIONS CONTROLS</u>	<u>STANDARDS (LB/10⁶BTU)</u>
GAS AND DISTILLATE OIL	LOW EXCESS AIR (LEA)	0.20 & 0.30
RESIDUAL OIL	LEA/STAGED COMBUSTION AIR (SCA)	0.30 & 0.35
COAL BOILERS		
STOKER	LEA	0.60
PULVERIZED	LEA/SCA	0.70

NO EMISSION STANDARDS RECOMMENDED FOR:

NONFOSSIL FUELS

CRUDE AND SHALE OILS

SLIDE 4. BENEFIT OF RECOMMENDED STANDARDS

● REDUCES GROWTH IN NATIONAL INDUSTRIAL BOILER EMISSIONS

PARTICULATE MATTER	-58,000 TONS (-43%)
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NITROGEN OXIDES	-53,000 TONS (-16%)
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● SPEEDS PERMITTING NEW BOILERS

<u>FUEL</u>	<u>NEW BOILERS (1984 - 1988)</u>
GAS/OIL	12
COAL	448
WOOD/SOLID WASTE	<u>123</u>
	583

A UTILITY PERSPECTIVE ON NO_x CONTROL

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ABSTRACT

This paper will review the status of legislative and regulatory activities that could require further NO_x emission reductions from existing and/or new coal-fired power plants. Revised ambient air quality standards, visibility protection requirements, revisions of New Source Performance Standards, application of Prevention of Significant Deterioration requirements, and acid deposition legislation will be discussed. When possible, comments will be made concerning the need for investing R&D resources in further NO_x control research.

I. INTRODUCTION

It is not just a formality when I say that as a representative of the Southern electric system, I am delighted to be here at this 1982 Joint Symposium on Stationary Combustion NO_x Control. My company is located in the Southeastern U. S. and consists of Georgia Power Company, Alabama Power Company, Gulf Power Company, Mississippi Power Company, Southern Company Services, Inc., and Southern Electric International. The System currently has over 18,500 MW of coal-fired generating capacity and expects to have over 22,000 MW of coal-fired capacity in the mid-1990's.

When we discuss NO_x control in our company, we have historically been concerned with protecting the ambient air quality standards and in more recent years purchasing boilers that will meet the New Source Performance Standards. In all cases, our facilities are in compliance with the current NO_x regulations. The need for or importance of supporting the development of greater NO_x control capabilities is most important when trying to evaluate how future legislative or regulatory activities will affect our

operations. Many of the advanced engineering efforts of the industry, related to NO_x control, are focused by EPRI. Working within the industry, advisory structure of EPRI, utilities must balance the need for NO_x research against other control technology development needs and the broad spectrum of other environmental and technology R&D programs that EPRI represents.

In my presentation today I would first like to comment on some of the air quality regulations and legislation that may affect NO_x emissions. Then I will comment on the engineering decisions that must be addressed if tighter NO_x controls are required.

II. AIR QUALITY REGULATION

When discussing air quality regulations, it is important to distinguish between local, regional and national air quality issues. Historically, the focus has been on the local air quality where the emphasis has been protecting human health and welfare by limiting the ambient concentration of a pollutant. For the most part, this focus has emphasized control strategies on a source by source basis. Regional and national air quality have become the emerging issue of the 1980's and are characterized by concerns over total atmospheric loading, long range transport and the ultimate fate of emissions. Acid rain is currently the most visible of the broad air quality issues that are being discussed in Washington.

Determining what the final form of a NO_x related regulation will be is no simple task. In addition, after a new regulation is established, uncertainties in modeling, monitoring, siting, meteorology and other variables make it difficult to determine immediately what effect a new regulation will have on a specific plant. However, I would like to review briefly the various areas where the Clean Air Act, currently or in the future, may influence emissions of oxides of nitrogen. When appropriate, I will discuss NO_x in relation to other pollutants.

II.-1 Ambient Standards

- A. The National Ambient Air Quality Standards are designed to protect the public health and welfare from adverse effects attributable to pollutants in the ambient air. There is currently an ambient standard for NO₂ equal to 0.05 ppm averaged over a year.
- B. If the air quality in an area attains the ambient standard, no control measures need be imposed. If not, the non-attainment provisions of the Act require the states to--
 - 1. Impose reasonably available control measures on all existing sources.
 - 2. Make reasonable further progress toward attainment.

3. Inventory emissions in the non-attainment areas.
 4. Impose a permitting program on new major stationary sources requiring--
 - a. Offsetting emissions so as to insure reasonable further progress.
 - b. The lowest achievable emission rate for major new sources.
 - c. The applicant's other sources in the state to be in compliance with their emission limitations.
 5. The deadline for reaching attainment is currently December 31, 1982. However, if a state has been making a good faith effort as determined by the EPA Administrator, extensions can be made to December 31, 1987 for CO and oxidants. If a December 31, 1987 deadline is granted for attainment of all ambient standards then there is a requirement to--
 - a. Require an alternative site analysis for major sources.
 - b. Establish an inspection and maintenance program for mobile sources.
 6. Retrofit of existing sources and adequate control or alternative siting of new sources could, therefore, be required for non-attainment.
- C. The 1977 Amendments to the Clean Air Act require EPA to consider the adoption of a new short-term NO₂ ambient standard and revision of the current annual standard. The statutory deadlines for both actions have run out. The EPA's present thinking would lead it to forego the short-term NO₂ option in favor of an annual standard in the 0.05 to 0.08 ppm range because it would adequately protect public health. Relaxation of the standard could reduce the number of non-attainment areas and the controls required. Similarly, EPA's selection of a more stringent standard than currently in place could require emission rollbacks for the additional non-attainment areas.

II.-2 New Source Performance Standards (NSPS)

- A. New sources that cause or contribute significantly to air pollution that reasonably may be anticipated to endanger public health or welfare must use the best system of emission reduction that has been adequately demonstrated. For power plants, the NSPS for NO_x is 0.6 lb/MBTU for bituminous coal and 0.5 lb/MBTU for sub-bituminous coal. The percentage reduction requirement of the NSPS for fuel burning facilities is folded into these numbers.

II.-3 Prevention of Significant Deterioration (PSD)

- A. PSD is a preconstruction permit program that requires best available control technology (BACT) for all pollutants regulated by the Act-- obviously NO_x is included. BACT must be at least as stringent as NSPS.
- B. There is a PSD "increment" system for SO₂ and particulate matter which constrains ambient concentration increases to various fractions of the ambient standards. While there are now no NO_x increments, the Act requires EPA to put an increment, or equivalent, system for NO_x into place.
- C. Even if increments are not exceeded, permits can be denied if a proposed source will have an adverse impact on the air quality related values of national parks and wilderness areas. Because certain oxides of nitrogen can impair visibility (one of the air quality regional values) NO_x emissions could influence new source permitting.

II.-4 Visibility Protection

- A. The visibility protection provisions of the Act require that certain major stationary sources install best available retrofit technology (BART) if they impair visibility in the national parks and wilderness areas.
- B. The states must also prepare long-term strategies for non-BART and non-PSD facilities to make reasonable progress toward the national goal of preventing any visibility impairment in the parks.
- C. Because NO_x emissions can impair visibility, the visibility protection provisions of the Act can be another source of controls for stationary and mobile sources.

II.-5 Acidic Deposition

To discuss the many facets of the acidic deposition issue would require an entire Symposium. My objective is to touch on those areas where NO_x control technologies are relevant. I personally believe that NO_x will be considered more important as R&D continues, therefore, I want to discuss the emission control strategies that are being considered in acid deposition legislation. To do this I must discuss SO₂. The Senate Environment and Public Works committee has voted out of committee S.1706, which would require an 8 million-ton reduction from 1980 levels of SO₂ emissions from electric utility plants in 31 states (all states east of the Mississippi River plus Arkansas, Minnesota, Louisiana, Iowa, and Missouri) by 1993. The new level of SO₂ emissions resulting from this reduction would be regarded as a ceiling which could not be exceeded. If innovative control technologies are used, compliance would not be required until 1995. The bill would also freeze total NO_x emission rates from electric utility plants at the 1980 level. In addition, EPA would be required to develop an inventory of sources

of oxides of nitrogen in the 31-state region. After 4 years, a National Academy of Sciences report would include recommendations on reducing emissions. The SO₂ roll-back would be prorated to utilities on the basis of emissions that exceed 1.5 lb/MBtu. Therefore, the bulk of the reductions would be required of the midwestern and southeastern states which use the moderate to higher sulfur coals. One quite conservative estimate, prepared by the U. S. Department of Energy on the effects of the S1706, indicates that in the early 1990's, utilities in the 31 states affected by the legislation would be spending an extra seven billion dollars (1982\$) in operating and maintenance costs each year. That same study also estimates that the cumulative capital costs over a thirty-year period will be more than 130 billion dollars (1982\$).

Because of the potentially high costs associated with the acid deposition issue, a great deal of environmental R&D is being performed. In this country, the electric power industry is committed to an extensive effort. The utility industry has sponsored and coordinated research on acid rain for more than 5 years through EPRI. It has spent more than \$15 million so far and more than \$66 million is targeted for future research. The coal industry and the petroleum industry are also very involved in acid rain research.

In the Federal Government, more than ten agencies conduct a wide variety of programs. Most heavily involved in the acid deposition issue are the Environmental Protection Agency, Department of Agriculture, Department of Energy and National Oceanographic and Atmospheric Administration. Other groups include the Fish and Wildlife Service, Forest Service, U.S. Geological Survey, Tennessee Valley Authority and the Council on Environmental Quality.

Ongoing federal activities provided a foundation upon which the National Acid Precipitation Program was established. In FY 1980, the various federal "mission" agencies spent or obligated about \$11 million on research programs directly related to acid rain; approximately \$13 million was spent or obligated in 1981, with over \$18 million expected for FY 1982 activities. The President's FY 1983 request to Congress proposing a \$22 million level for federal acid rain research indicates the concern of Administration for this issue.

We strongly endorse and support the EPRI, EPA, and others who are trying to perform this environmental research in the next 5-6 years or sooner so that policy and regulatory decisions can be made in a responsible way.

II.-6 Summary

Even if one or more of the local, regional or national regulatory requirements come to pass, there will still be uncertainties as to where utility NO_x emissions fit in the overall control strategy. However, I hope I have made the point that most of the potential regulations related to NO_x will focus on controlling emissions from existing sources. For regulations such as the short-term NO₂ standard (local air quality), a key issue will be

balancing the control of stationary and mobile sources. Figure 1 illustrates the 1980 emissions of these sources for the eastern U. S. Figure 2 illustrates the same data in an emission density form by state. Emission density is determined by dividing a states total emissions by state area. One way to interpret Figure 2 is to say that it displays the data in terms of equal state areas so that a state like Illinois can be compared with an equal state carried out of the Northeast. Questions concerning urban versus rural sources, ground level versus elevated emissions and atmospheric chemistry are not addressed in this form of data presentation. Obviously, questions concerning these factors must be included for a complete assessment of the issue. However, I believe that these figures illustrate that focusing only on utility emissions will not properly address the question.

With respect to a regional issue like Acid Deposition, potential regulations have even more uncertainties concerning where utility NO_x emissions fit into the problem. Figure 3 illustrates the SO_2 and NO_x emission densities in 1980 for various source categories in the 31 states. Recall that currently proposed legislation requires only SO_2 emission reductions. The NO_x emission rate freeze only affects coal conversions although required studies might change this. I believe that Figure 3 illustrates that focusing only on SO_2 may be a mistake. Several researchers in the area of atmospheric chemistry feel that NO_x and other oxidants play an important role. Again, the issue of local sources versus long range transport, height of emission release and atmospheric chemistry will play a part in resolving this issue of where NO_x fits. Finally, Figure 4 illustrates the before and after effects of current legislation using the data from Figure 3. I believe that Figure 4 supports my view that the current legislative strategy will not be effective.

For this audience, it is worth noting that in a previous version of the Senate Bill, NO_x could be substituted for SO_2 on a 2 for 1 basis and also had a total emission freeze at the 1980 level. Although the 2 to 1 ratio was presented with no scientific support, it made an interesting calculation to see how it affected the cost for emissions reductions if NO_x reductions were used to offset SO_2 reductions. The bottom line for our company was that for such large emission reduction requirements there were limits on the tonages available for control. On a two to one basis, NO_x emissions were less than one eighth of our SO_2 emissions. Therefore, NO_x reductions did not significantly affect our cost estimates. Included in this analysis was the consideration that since most of our large units have emission rates that are less than or close to the current NSPS for NO_x , the uncertainties concerning operating and maintenance impact associated with further NO_x reduction was not deemed cost effective.

Well, I think I have described a picture to you of many uncertainties and not many definitive answers. As an individual in my company who is responsible for both control technology development (FGD) and environmental assessment efforts (atmospheric chemistry, ecological effects, health effects) it is always difficult to balance R&D dollars between technology development and environmental studies. Small changes in the regulatory boundary conditions can have tremendous financial impact. This is reflected

at EPRI by the difficulty in balancing the investment in environmental studies vs. technology R&D. This is an ongoing question to be addressed.

I would now like to discuss an engineering view of the NO_x issue.

III. ENGINEERING DECISIONS

If utilities need to reduce current NO_x emission levels, then from the engineering viewpoint, our concerns fall into the categories of new and existing (or retrofit) plant applications. In either case an evaluation of combustion versus post combustion NO_x control is required. As in the case of most engineering studies, this starts with a consideration of costs. Current EPRI data indicate that the post combustion option of selective catalytic reduction (SCR) is at least a factor of 10 more expensive than combustion NO_x control strategies. SCR is projected to have a \$50-\$100/KW capital cost and O&M costs ranging from 6-13 mills/KWH (ref. Oct. 1982, EPRI Journal). SCR is expected to result in emission rates of the order of 0.2 lb/MBtu on a new unit. Current EPRI studies focus on the effects of the SCR system on the performance and reliability of downstream equipment such as air heaters, FGD, and particulate control equipment. The Law of Inverse Ignorance says that costs will go up for new units and make SCR the technology of last resort for new or retrofit applications.

Therefore, the NO_x control option which seems to currently have the greatest economic promise is combustion NO_x control. With respect to new units, where boilers and burners are designed to be compatible from the start, emission rates similar to those achievable by SCR may be possible at much less cost using combustion controls. With respect to retrofit applications, the emission reductions may be somewhat less than achievable on new units, but the cost per ton of NO_x removed will still be much less compared to SCR. Combustion modification costs will depend on several variables including manufacturer, boiler type and fuel characteristics. Capital cost estimates will range from as low as \$0.5/KW to as high as \$15/KW or more for extreme retrofit cases (ref. personal discussions with vendors and researchers). Many of the processes now under development are targeted for the 0.2 lb/MBtu emission level. A key requirement for the development of these low NO_x burner options is that operation and maintenance costs must be near zero compared to conventional combustion systems. We strongly support fundamental combustion studies which can assure that if additional controls are needed on existing units, we will not jeopardize the operation or performance of a perfectly good furnace trying to do it.

IV. CONCLUSIONS

If further significant reductions in utility NO_x emissions are mandated, the major application of future NO_x control technologies will be on existing plants. This focus on existing units represents a major turning point in application of NO_x controls.

Combustion NO_x controls offer the promise of being the most cost effective means of NO_x emission reductions.

When selecting the use for its R&D dollars, the utility industry should follow the development of new NO_x control technologies. This will be done primarily through its R&D program at EPRI.

I believe that these conclusions are consistent with the objectives of this Symposium, which is to offer the attendees a comprehensive picture of recent developments in NO_x control technology. I hope you have a very productive meeting.

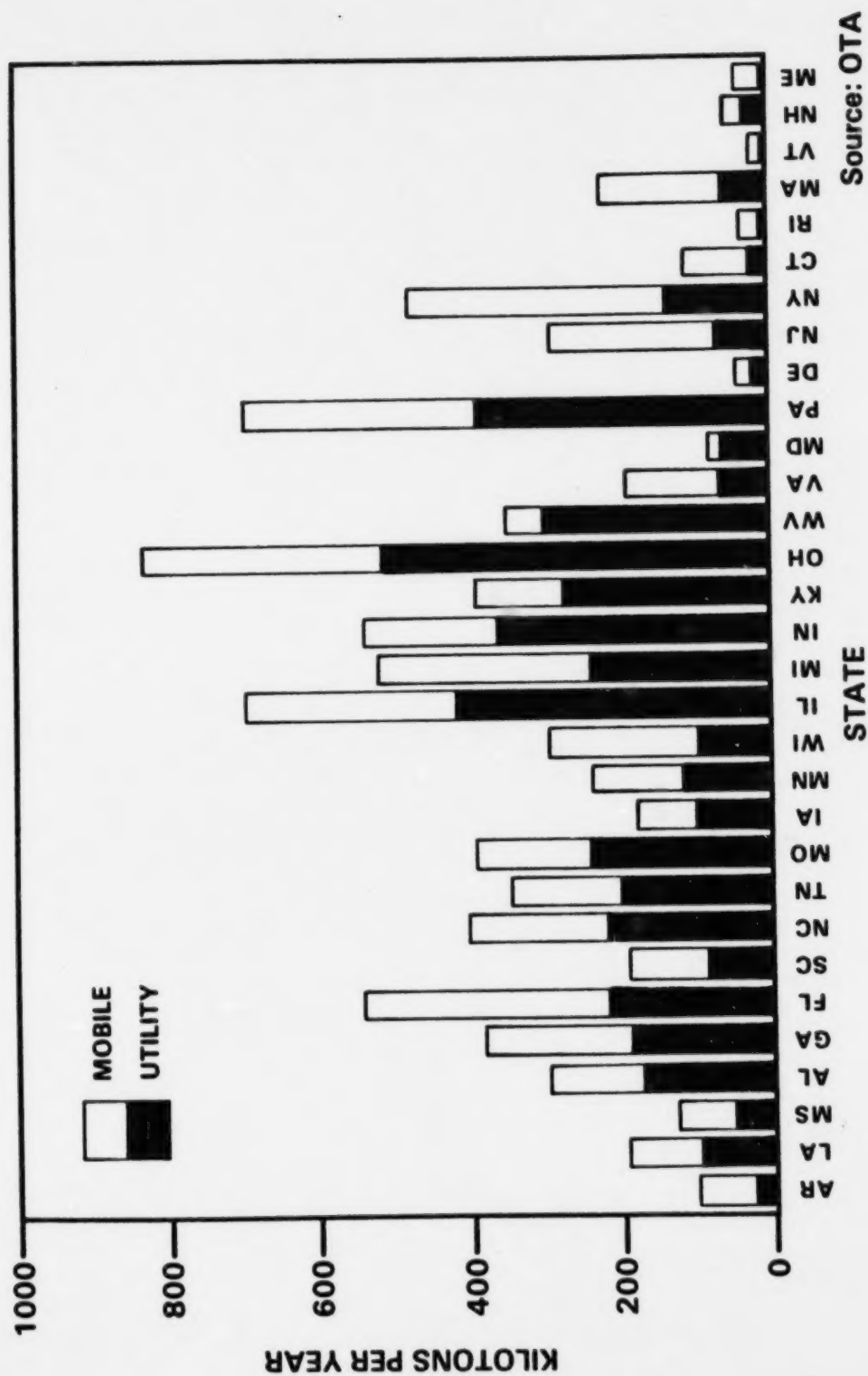


Figure 1. 1980 NO_x emissions from utility and mobile sources in the eastern United States (all states east of Mississippi River plus AR, IA, LA, MN, and MO).

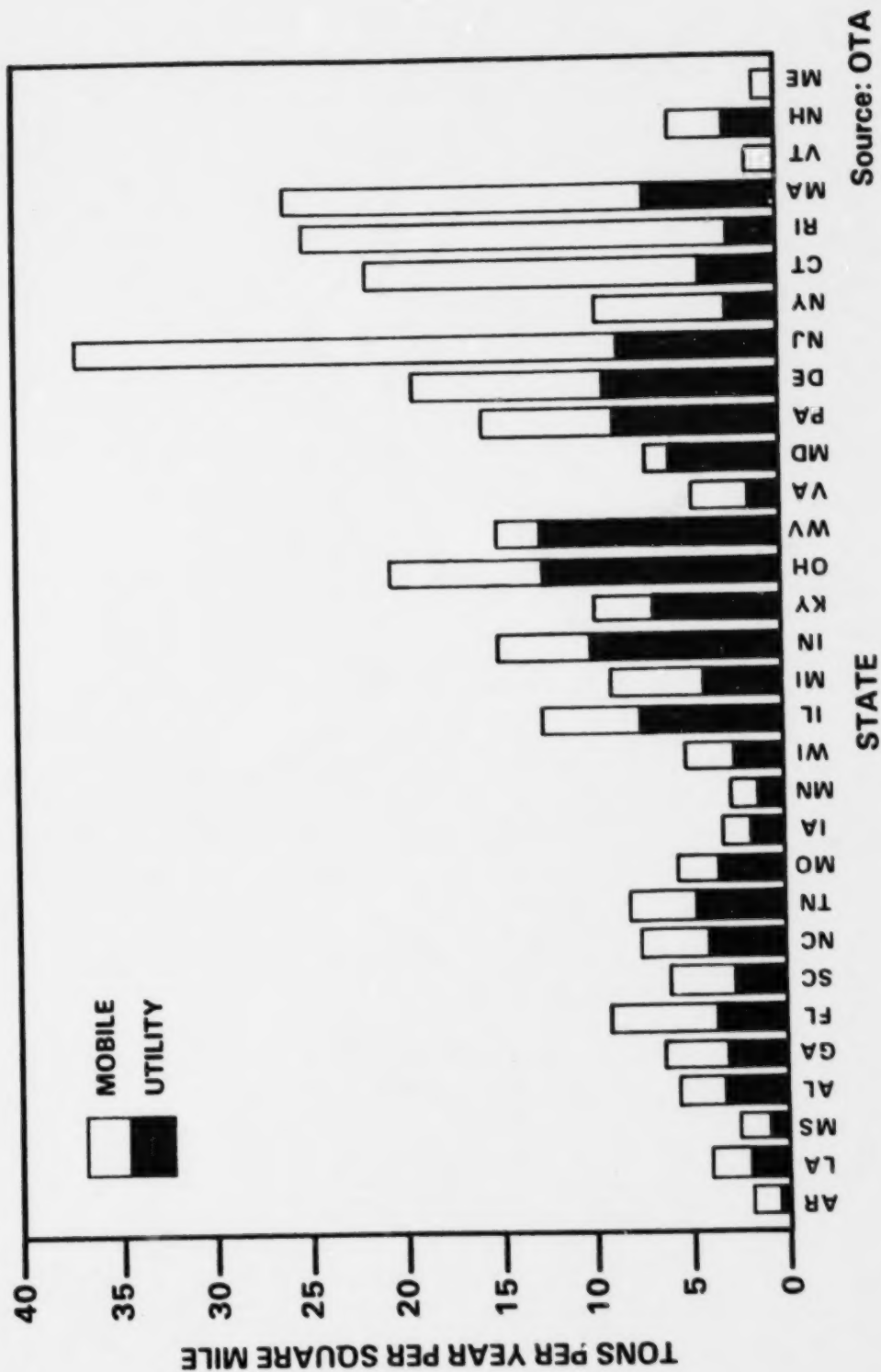
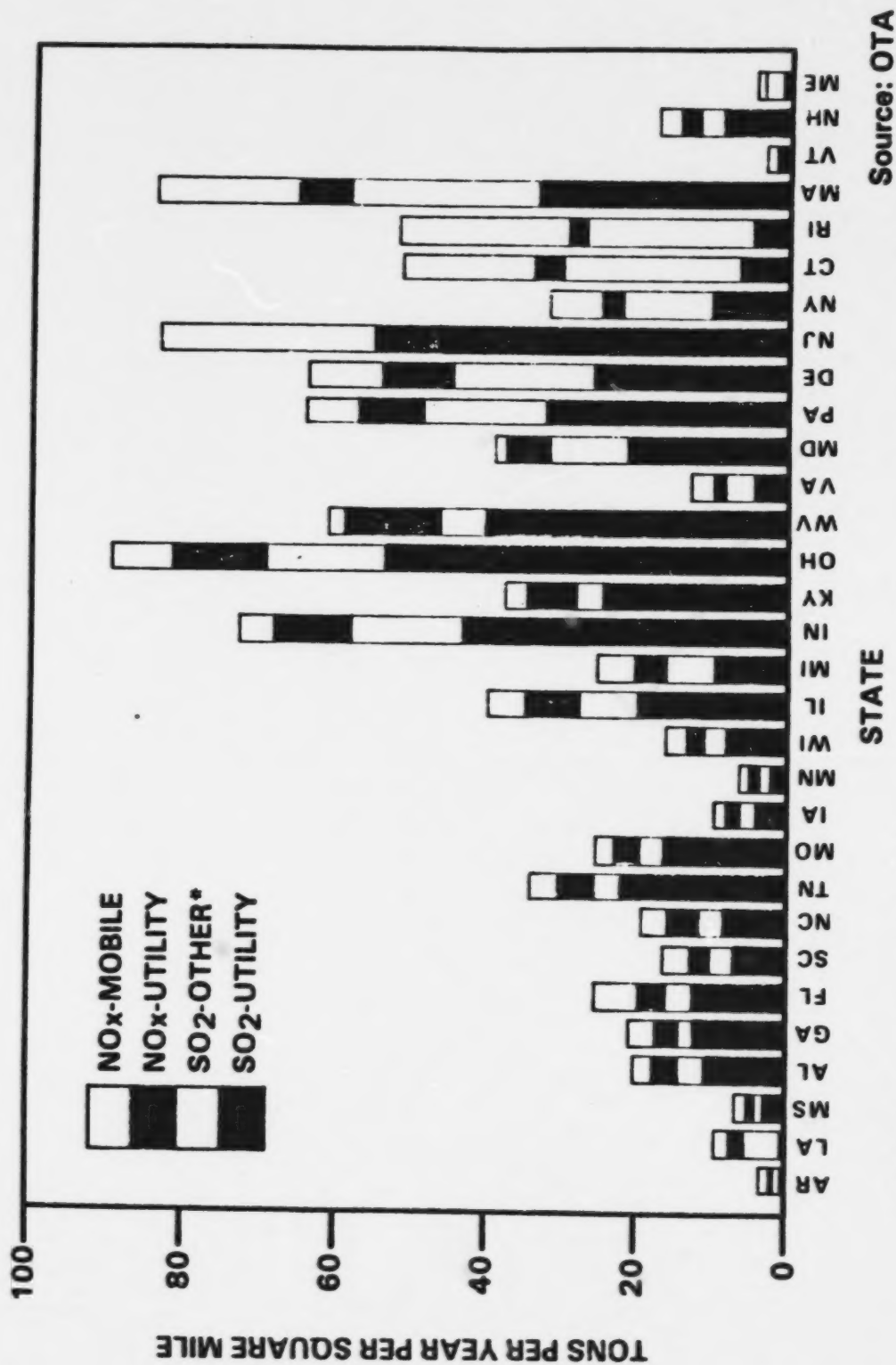


Figure 2. 1980 NO_x emission density for utility and mobile sources in the eastern United States (all states east of Mississippi River plus AR, IA, LA, MN, and MO).



*Residential, commercial, industrial process, refinery, smelter, incinerator, etc.

Figure 3. 1980 SO₂ and NO_x emission density in the eastern states (all states east of the Mississippi River plus AR, IA, LA, MN, and MO).

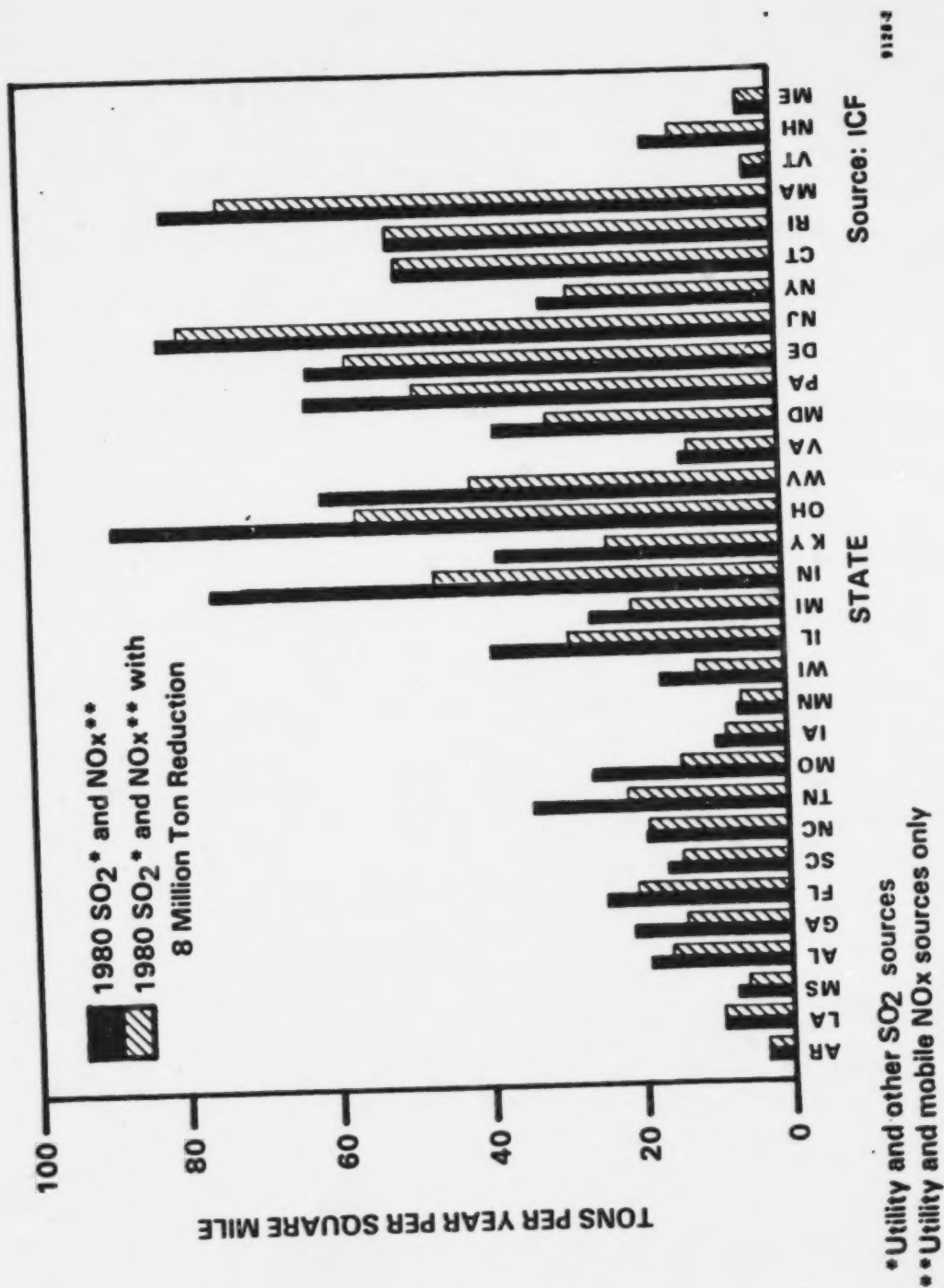


Figure 4. 1980 SO₂ and NO_x emission density in the eastern states Mitchell Bill evaluation (all states east of the Mississippi River plus AR, IA, LA, MN, and MO).

UPDATE ON ACID DEPOSITION

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ABSTRACT

Acid deposition is a complex phenomenon which involves the interaction of a variety of atmospheric processes. These include meteorological processes which contribute to transport, dry deposition, and wet scavenging as well as chemical transformation processes which predominantly produce the acidic substances from precursor emissions such as NO_x and SO_2 and also effect the processes of dry deposition and wet scavenging. This presentation provides a review of these atmospheric processes and discusses the outstanding issues which remain to be resolved. In addition, a review of present generation acid deposition simulation models is presented with a discussion of their shortcomings and the direction future generations of models are likely to take. Finally, a brief overview of the Atmospheric Processes Program underway as part of the Federal Interagency Task — National Acid Precipitation Assessment Plan is also presented.

SESSION II

MANUFACTURERS' UPDATE OF COMMERCIALY
AVAILABLE COMBUSTION TECHNOLOGY

Chairman, David Eskinazi, EPRI

STATUS OF NO_x CONTROLS FOR RILEY STOKER
WALL-FIRED^x AND TURBO-FIRED BOILERS

By: -

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ABSTRACT

Large pilot scale and full size field data are presented on a new low NO_x retrofit burner design for pulverized coal wall-fired boilers. NO_x reductions of 50 to 60 percent have been achieved with this retrofit burner on three large (greater than 300 MW) utility boilers. An update of Turbo furnace NO_x controls is also given. NO_x field results are presented on the effects of underfire air and variable direction coal spreaders. In addition, the results of pilot scale burner aerodynamic tests are discussed, and the effects of staged combustion on furnace heat transfer are predicted.

INTRODUCTION

Two years ago Riley Stoker initiated a comprehensive R&D program to develop low NO_x combustion systems for both pulverized coal wall-fired and Turbo fired boilers. Our wall-fired burner program has led to the development of the Riley Controlled Combustion Venturi (CCV) burner. The CCV burner is a low-NO_x single register burner designed for installation on existing as well as new wall-fired steam generators.

This CCV burner development effort included both pilot scale tests, and field tests on three utility boilers. Pilot scale tests were conducted at 50×10^6 Btu/hr in a single-burner test facility. In addition to the CCV burner, pilot scale tests were also conducted on a prototype Riley Distributed Mixing Burner (DMB) design. Following the pilot scale tests, the CCV burner was retrofitted and tested on a single wall-fired 400 MW boiler, and two 360 MW opposed wall-fired boilers. All of these boilers had been previously equipped with Riley Flare burners. The installation of CCV burners resulted in a 50 to 60 percent reduction in NO_x emissions.

Our Turbo furnace development program has included aerodynamic tests on a one half scale Directional Flame burner model, and field tests on several utility dry bottom Turbo furnaces. Field tests were conducted on

Turbo units equipped with modified Directional Flame burners, and with a portion of the combustion air admitted beneath the burners. Burner modifications included the use of variable direction coal spreaders.

Currently, we are investigating advanced Turbo designs staged with both overfire and underfire air. An analytical furnace model is being used to study the effect of staged combustion on furnace heat transfer.

WALL-FIRED BOILERS

Prior to 1971 the majority of Riley Stoker pulverized coal-fired boilers were wall-fired. In fact, wall-fired boilers represent over 60 percent of the pulverized coal utility boilers put into service by Riley Stoker since the mid-1950's.

Riley wall-fired boilers built prior to the New Source Performance Standards (NSPS) are equipped with either single (Figure 1) or double register Riley Flare burners. The Flare burner is a circular swirl stabilized burner. It is designed to maintain intense stable combustion over a wide load range. NOx field emissions varying from 570 to 970 ppm (1,3) have been measured on this conventional pre-NSPS burner design.

Low NOx Burners

Our low NOx wall-fired burner program began in January of 1980. Under this program, pilot scale combustion tests were conducted on three one third scale (50×10^6 Btu/hr) circular burners:

- Flare Burner
- Controlled Combustion Venturi Burner
- Distributed Mixing Burner

Baseline performance was established on the pre-NSPS Flare burner. Pilot scale Flare burner data were also compared directly to performance data from specific full scale field units.

Controlled Combustion Venturi Burner. The CCV burner, shown in Figure 2, is similar in design to the pre-NSPS Flare burner. The coal nozzle and coal spreader, however, have both been modified. In contrast with the Flare burner, the CCV coal nozzle is smaller in diameter and includes a venturi section. The Flare burner multivane coal spreader has been replaced by a four bladed conical shaped spreader. In the pilot scale burner both spreader position and the nozzle set back position were adjustable.

The CCV burner venturi section serves to concentrate the coal in the nozzle center creating a fuel rich zone with progressively leaner mixtures toward the nozzle periphery. The conical spreader divides the coal stream into distinct layers of fuel rich and lean mixtures. The axial velocity of this primary stream is closely matched to the secondary air velocity.

Secondary air swirl is controlled by a single register. Both the register and required burner opening are identical to the Flare design.

Riley Distributed Mixing Burner. As stated earlier, pilot scale tests were also conducted on a 50×10^6 Btu/hr prototype Riley Distributed Mixing Burner (DMB). The Riley DMB is designed according to criteria developed under several EPA low-NOx burner development programs (3,4). As shown in Figure 3, the burner is equipped with outboard tertiary air ports for staged combustion. The Riley DMB also incorporates the same venturi coal nozzle and conical coal spreader as that used in the CCV burner.

The DMB is equipped with two registers for swirl control. A damper and perforated plate are located at each register inlet for flow control and measurement. This dual register design permits independent control of swirl and air flow rate to each secondary air passage.

Design characteristics for all three Riley circular burner designs are summarized in Table 1.

Pilot Scale Tests

The single burner pilot scale combustion tests were conducted at the Energy and Environmental Research Corp. (EER) Test Facility in El Toro, Calif. The tests were conducted at firing rates up to 50×10^6 Btu/hr in the EER Medium Tunnel (MT) furnace. The MT furnace is a 14 ft. diameter by 20 feet long horizontal axis steel vessel. The inside surface of the vessel is partially covered with insulating refractory to simulate the overall furnace heat absorption of field operating boilers. The entire exterior surface of the furnace is spray cooled.

Results of the pilot scale testing are shown in Figure 4 for a high volatile C bituminous coal. A comparison of pilot scale Flare burner results with field data indicated pilot scale flame characteristics and overall burner performance were representative of full-size Flare burners.

CCV burner NOx emissions were approximately 55 percent lower than baseline Flare burner results. The DMB tests were conducted at various settings with the tertiary air ports closed and open. The unstaged DMB results were comparable with the CCV burner tests results. NOx emissions for the DMB staged (i.e., tertiary air ports open) to between 80 to 93 percent burner zone stoichiometry were approximately 64 percent lower than Flare burner emissions. The DMB test program was conducted largely for comparative purposes and did not include the range of design and operating conditions covered in the CCV burner test program. Consequently, the optimum DMB design was not determined during these tests.

In both the CCV burner and DMB tests we found burner performance was significantly affected by nozzle/spreader design. Nozzle spreader design appears to have a significant impact on air/fuel mixing in the near burner region. The venturi nozzle/conical spreader design provides the

necessary range of control for achieving minimum NO_x emissions with satisfactory combustion efficiency.

Flame shapes observed for both the pre-NSPS Flare burner and CCV burner are illustrated in Figure 5. The Flare burner produces a short, intense conical shaped flame. In contrast, the CCV burner produces a more gradually mixed flame with a short bulbous section close to the burner followed by a long downstream tail. The burner parameters controlling this flame shape are high swirl register settings, and nozzle/spreader location and design.

Field Retrofit Tests

Following the pilot scale testing the CCV burner was retrofitted and tested on three utility boilers.

Single Wall-Fired Boiler Test. The first field unit tested was Duck Creek Unit No. 1 owned and operated by The Central Illinois Light Company. As shown in Figure 6, Duck Creek Unit #1 is a 400 MW boiler with 24 burners mounted on the front wall. The original equipment burners were Riley Flare burners rated at 156×10^6 Btu/hr. The fuel was an Illinois Crown II seam high volatile C bituminous coal with a heating value in the 10,000 to 11,000 Btu/lb range.

Duck Creek Unit #1 was retrofitted with 24 CCV burners during the fall of 1981. Underfire air (UFA) ports were also installed below the lower burner row to control windbox pressure. In addition, flue gas recirculation, which originally entered the furnace through the burners, was rerouted to enter the furnace through the rear wall for steam temperature control. During boiler operation with the flue gas recirculation (FGR) fan off, 10 percent of the total combustion air was bypassed away from the windbox and introduced into the FGR ductwork for cooling purposes.

As shown in Figure 7, NO_x emissions 50 percent below baseline pre-NSPS levels were measured at design excess air levels with underfire air closed and 10 percent bypass air. Estimated full load emissions without bypass air are also shown. Measured CO levels are low and comparable to pilot scale test results. The effect of UFA on emission levels is shown in Figure 8. At 22 percent excess air NO_x emissions were between 320 ppm and 440 ppm (3% O₂) depending on the amount of UFA and register vane position. The bypass air was off during these tests.

No significant change in the overall heat absorption characteristics of both the radiant furnace and superheater were observed during the CCV burner testing (5).

Samples of furnace bottom ash, economizer hopper ash and precipitator ash were sampled during the testing and analyzed for loss on ignition according to ASTM procedures (6). The results are compared for various test conditions in Table 2. The total amount combustible in the ash is slightly higher for the CCV burner when compared with Flare burner operation with no

flue gas recirculation. This increase, however, corresponds to a decrease of only 0.25 percent in boiler efficiency (5). Precipitator ash ignition loss and CO data as a function of NOx emission are presented in Figure 8. Although there is significant scatter in the data, both loss on ignition and CO increase as NOx decreases.

Opposed Wall-Fired Boiler Tests. CCV burners were also retrofitted on Carolina Power and Light Company Roxboro Units 4A and 4B. Twelve CCV burners, mounted on both front and rear waterwalls of each 360 MW unit, were installed to replace the pre-NSPS Flare burner equipment. Existing underfire air ports were used in conjunction with the CCV burners for both windbox pressure control and NOx control.

As shown in Figure 9, Roxboro units 4A and 4B are also equipped with conventional overfire air ports. However, since low burner zone stoichiometries were not required to meet retrofit NOx control goals, the overfire air ports were closed during CCV burner operation. The coal fired during these tests was a high volatile A bituminous coal with a heating value in the 12,000 to 13,000 Btu/lb range.

Unit 4A full load NOx emission levels were reduced 50 percent below pre-NSPS levels with acceptable unit performance. As shown in Figure 10, at design excess air NOx was reduced from 810 ppm to 353 ppm with CCV burners installed and UFA fully open. Burner zone stoichiometry was 108 percent. Closing UFA ports increased NOx to 397 ppm with the burners still operating slightly staged due to 6.0 percent combustion air leakage to other parts of the boiler.

Unit 4B full load test results also showed a 56 percent reduction in NOx with acceptable unit performance. NOx at these optimum burner conditions averaged 357 ppm. As experienced at CILCO Duck Creek 1, no significant change in steam temperature and overall boiler performance was observed (5).

Comparison of Pilot Scale and Field Test Results

Pilot scale NOx emissions for Riley pre-NSPS and low NOx burners are compared with boiler test results from Duck Creek Unit 1 and Roxboro 4 in Figure 12. NOx emissions are plotted as a function of Burning Area Heat Release (1,2) or heat release per cooled area in the furnace heat release zone. NOx emissions are 20 to 30 percent higher under multiple burner field conditions than for single burner pilot scale conditions. Flue gas recirculation was found to have little effect on NOx emissions in the 50×10^6 Btu/hr pilot scale tests.

TURBO-FIRED BOILERS

In addition to developing circular burners for retrofit on wall-fired boilers, Riley Stoker is continuing its effort to evaluate and

develop low NOx Turbo furnace combustion systems.

As illustrated in Figure 13, dry bottom Turbo fired boilers are characterized by a venturi shaped lower furnace. Directional Flame burners are installed in single rows on opposite downward facing walls. A schematic of the Directional Flame burner is shown in Figure 14. Axial flow is produced at the burner by essentially parallel secondary air and primary air coal jets. The jets are introduced to the furnace through slots formed in the furnace walls. This type of aerodynamic system produces long turbulent diffusion flames. In contrast to wall-fired boilers, these flames are dominated by far field effects.

The directional air vanes (Figure 14) are adjustable so that secondary air can be directed into or away from the primary stream. Conventionally staged Turbo furnaces are equipped with overfire air ports located in the furnace "venturi throat."

This unique burner/furnace system produces downward directed intersecting flames which penetrate to the lower furnace, turn, and curl upward. Hot flue products recirculate from the lower furnace flowing upward past the burner level to the upper furnace where they mix with the remaining fuel and air.

Burner Aerodynamics

The combustion chemistry of large scale systems cannot be uncoupled from fluid dynamics. Detailed measurements made by Michel and Payne (7) indicate that mixing is the determining mechanism in the combustion of long pulverized coal flames. Because of the difficulty and expense of making detailed measurements in large scale combustion systems, we are performing cold flow aerodynamic model studies to characterize the effect of burner design parameters on mixing patterns. An automated five-hole pitot tube system is being used to map three dimensional flow fields immediately downstream of the burner nozzles. Axial velocity profiles measured on a one-half scale model of a 150×10^6 Btu/hr Directional Flame burner are presented in Figures 15 and 16.

Figure 15 shows the development of downstream axial velocities in a vertical plane perpendicular to the coal nozzle. The air flow profiles are not axisymmetric. This reflects the influence of the secondary air vane position. A low velocity internal recirculation zone can be observed immediately downstream of the coal nozzle. The developing near field mixing region appears to extend up to one characteristic burner dimension (throat height) downstream.

Axial downstream velocity profiles in a perpendicular horizontal plane located just beneath the coal nozzle are presented in Figure 16. The air flow profile in this plane is axisymmetric. Again, the central air jet is absorbed by the outer secondary air jets approximately one burner throat height downstream.

Turbo Furnace Field Tests

Nozzle geometry and secondary air vane position can significantly affect mixing patterns close to the burner. We have recently conducted field tests on two utility Turbo furnaces with modified Directional Flame burners. These modifications included the installation of variable angle coal spreaders. Underfire air ports equipped with tilting vanes were also installed in the lower furnace side walls. As shown in Figure 14, the coal spreader was designed to direct the primary coal stream vertically downward. The underfire air ports were added as a means of staging the combustion. This firing approach is similar to that used on arch fired boilers (8).

Field tests results from a 370 MW Turbo unit equipped with 24 Directional Flame burners and fired by Wyoming sub-bituminous coal (8000 to 9000 Btu/lb) are shown in Figure 17. NO_x emissions are presented as a function of the downward spreader angle and underfire air. The amount of underfire air is expressed as a percentage of total air flow. A perforated plate was installed above the coal nozzle for these tests to block air flow and bias more secondary air downward beneath the coal nozzles. Coal spreader angle appears to have the strongest individual effect at these operating conditions and level of staging (5-15%). This is particularly true at the steeper (downward) angles. We believe the leveling off and slight increase of NO_x emissions beyond 70 degrees down may be due to the mechanical spreader design. A portion of the coal stream may be bypassing over the top of the spreader at this position. Underfire air, however, did reduce the carbon content of the furnace bottom ash.

Variable downswept coal spreaders have also been installed and field tested on a 540 MW Turbo furnace firing Montana sub-bituminous coal. Full load NO_x emissions varied with spreader angle and secondary air vane position ranging from 360 to 230 ppm (3% O₂). These emission levels were obtained unstaged, that is, without underfire air and without a perforated plate in the upper secondary air stream above the coal nozzle. Unstaged NO_x emission field data for this unit are presented in Figure 18 as a function of secondary air vane position. As discovered in previous Turbo furnace field tests (9) vane position No. 2, which directs both upper and lower secondary air streams away from the primary stream, results in the slowest mixing and lowest NO_x emission levels.

Staged Combustion Heat Transfer

Riley Stoker is also evaluating the application of advanced staged combustion concepts to the Turbo furnace design. A multi-zone furnace model is being used to assess the effect of these combustion techniques on heat absorption rates and temperature distribution in the radiant furnace. The model, shown schematically in Figure 19, incorporates the lower furnace geometry and flow pattern unique to the Turbo furnace design. Model predictions have been verified against extensive field measurements obtained on a 490 MW pulverized coal fired Turbo furnace.

Predicted central gas zone temperatures for various degrees of staging with overfire air are presented in Figure 20. Lower temperatures are produced in the burner heat release zone as staging ratios are increased. This temperature decrease is caused by the combined effects of reduced lower furnace heat release and quenching by overfire air jets.

FUTURE WORK

In the coming year, we plan to continue our development of both wall-fired and Turbo-fired combustion systems. Further development tests will be conducted on our retrofit low NO_x burner design, the CCV burner, in the recently completed 100x10⁶ Btu/hr Riley Coal Burning Test Facility (CBTF). This additional operating experience will be applied to advanced fuel and air staging tests which will also be conducted in the CBTF next year. These tests will be performed under a retrofit low NO_x control development program sponsored by the Electric Power Research Institute.

A 100x10⁶ Btu/hr Riley DMB will be tested in EPA's Large Watertube Simulator located at the Environmental Research Corp., El Toro, California, under EPA Program No. 68-02-3913. The test program will include direct injection of sorbents for combined in-flame NO_x and SO_x control.

In addition, advanced burners for Turbo fired applications will be tested in the Riley CBTF. Burner designs incorporating advanced stage combustion and distributed mixing techniques will be investigated in this program.

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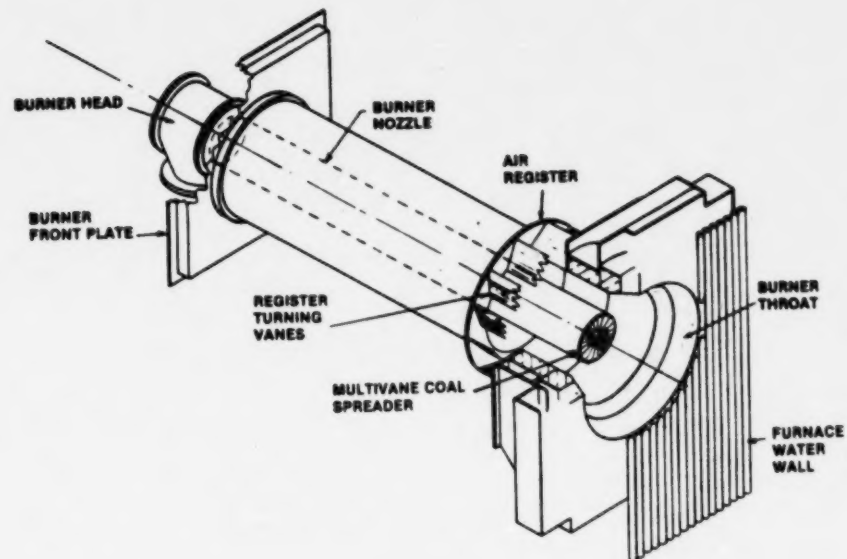


Figure 1 Flare Coal Burner

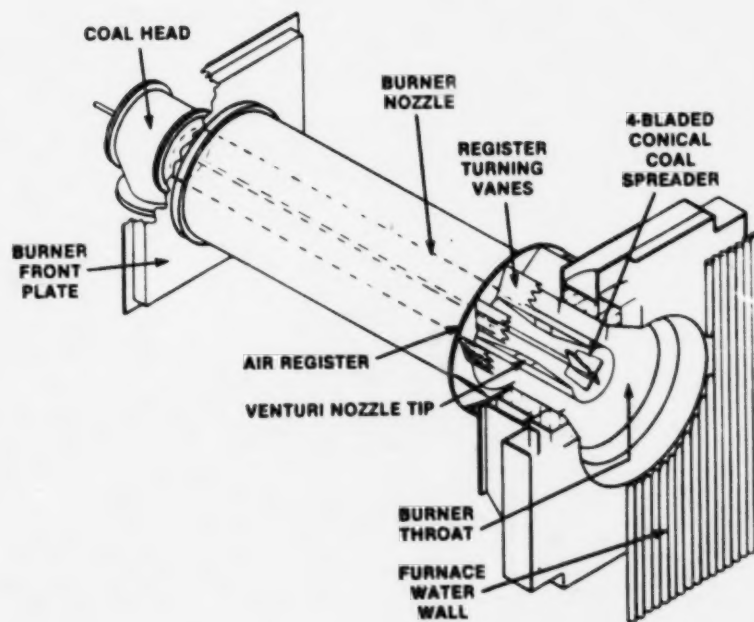


Figure 2 Controlled Combustion Venturi (CCV) Burner

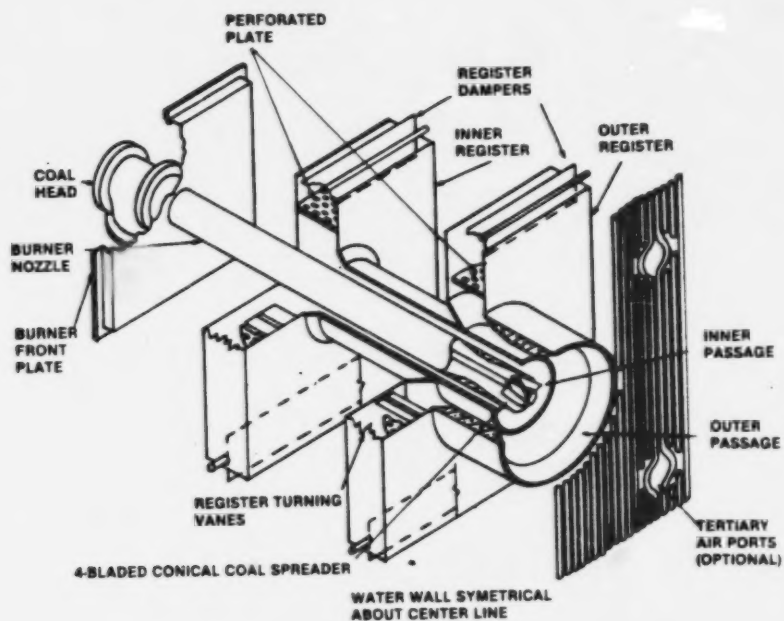


Figure 3 Distributed Mixing Burner

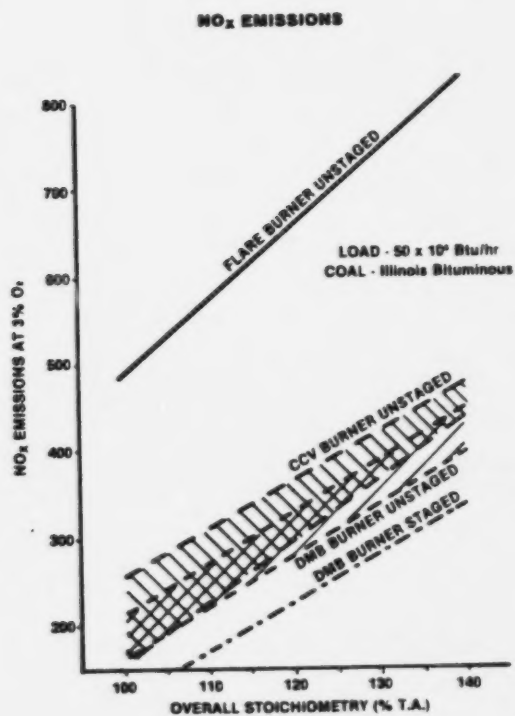


Figure 4 Pilot Scale Combustion Test Results

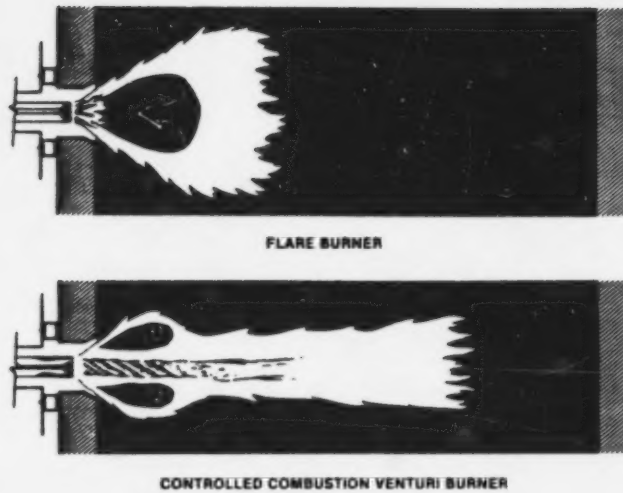


Figure 5 Schematic Typical Flame Forms

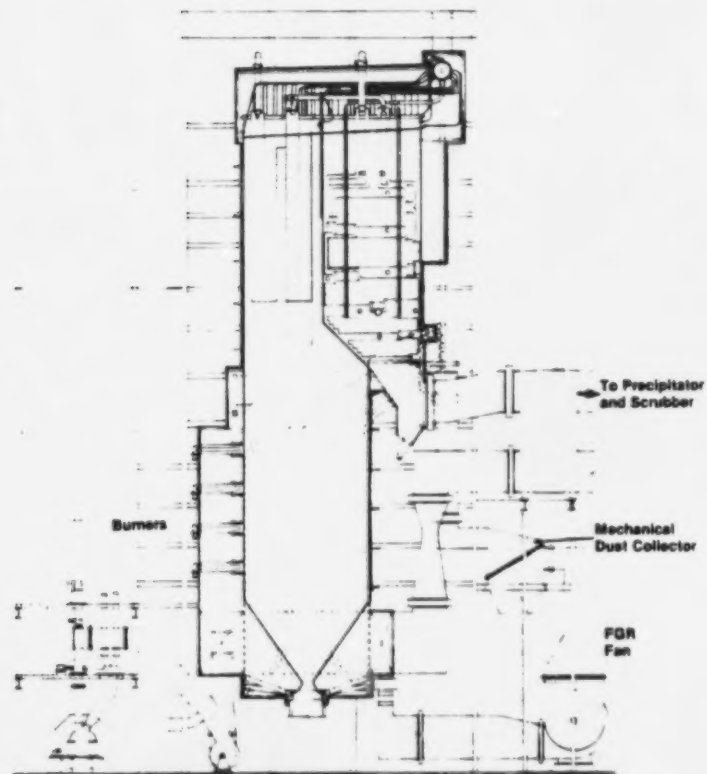


Figure 6 Central Illinois Light Co., Duck Creek Unit No. 1

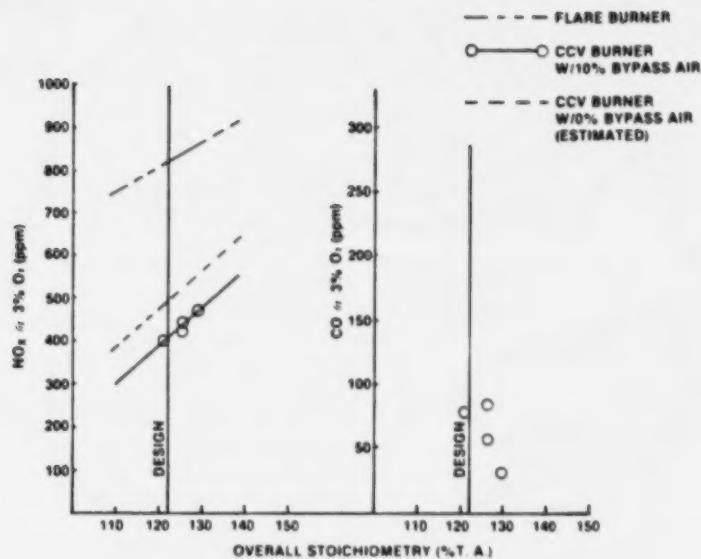


Figure 7 Field Test Results at Cilco Duck Creek Unit 1 (UFA Ports Closed)

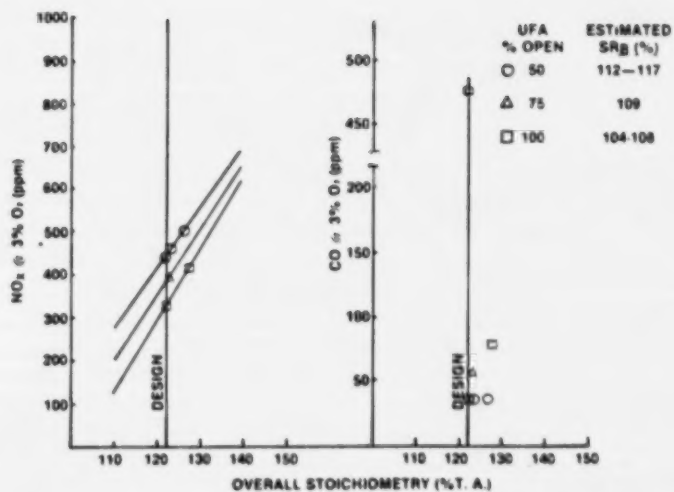


Figure 8 Field Test Results at Cilco Duck Creek Unit 1 (UFA Ports Open and Bypass Air Closed)

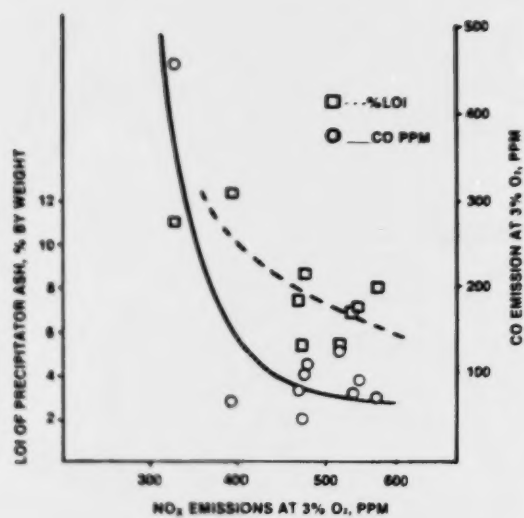


Figure 9 Loss on Ignition and CO Emissions as a Function of NO_x Emissions at Cilco Duck Creek 1

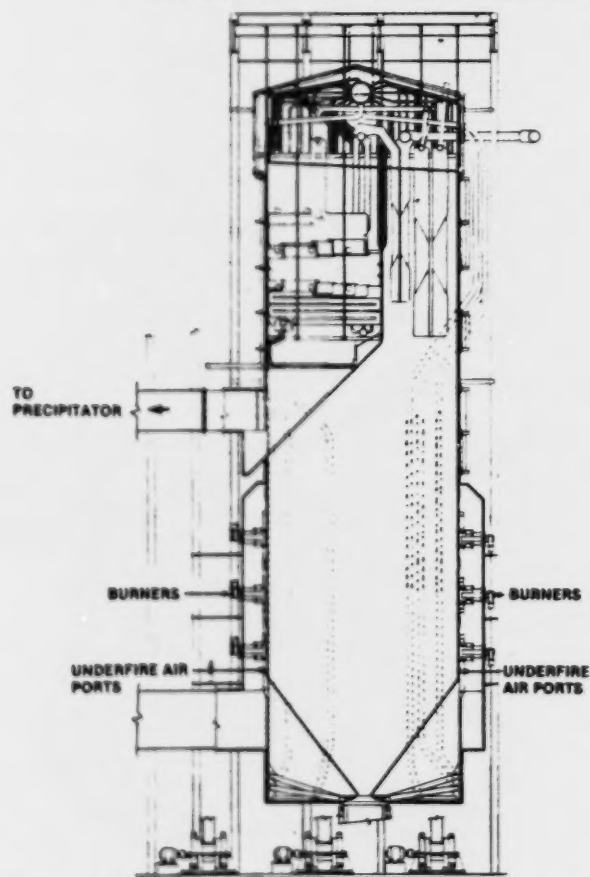


Figure 10 Carolina Power and Light Co., Roxboro Units 4A and 4B

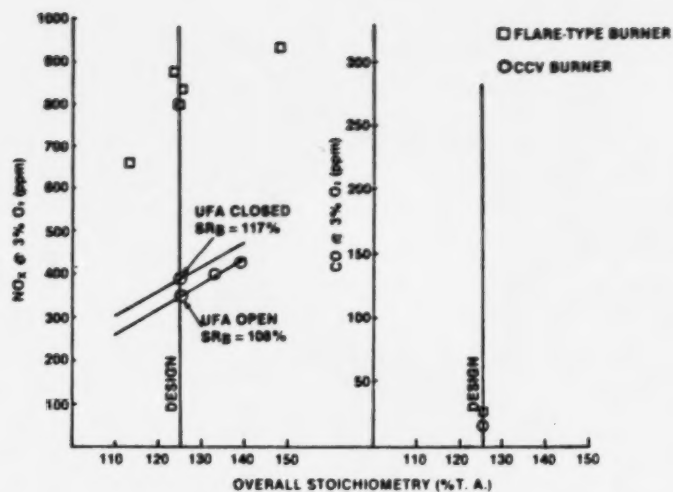


Figure 11 Field Test Results at CP&L Roxboro Unit 4A
(UFA Ports Open and Closed)

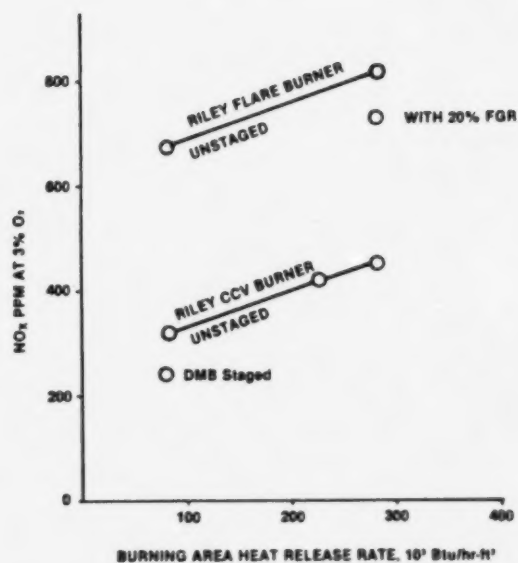


Figure 12 NO_x Emissions Pilot Scale on Wall-Fired Boilers Results

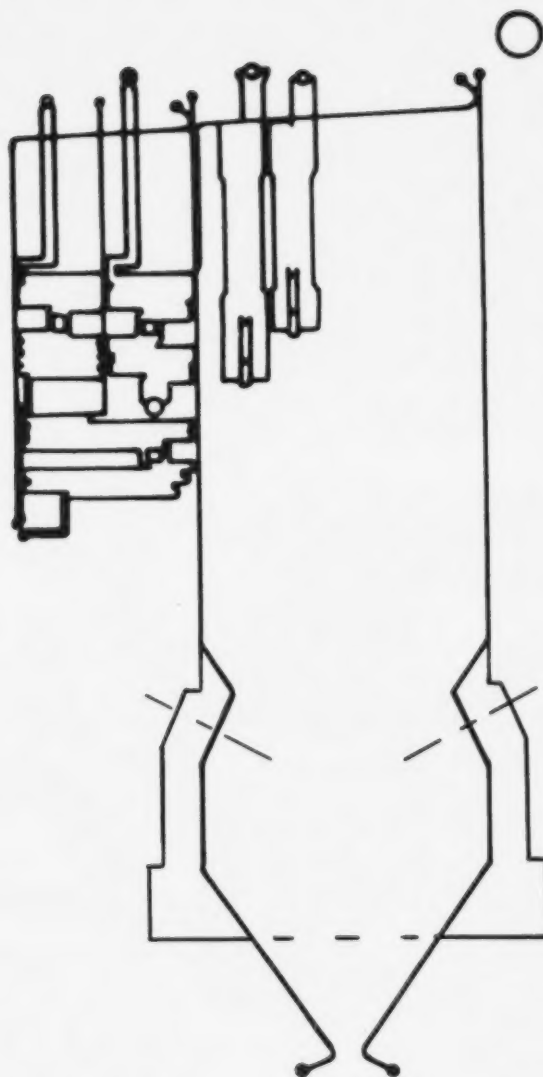


Figure 13 Dry Bottom TURBO® Furnace

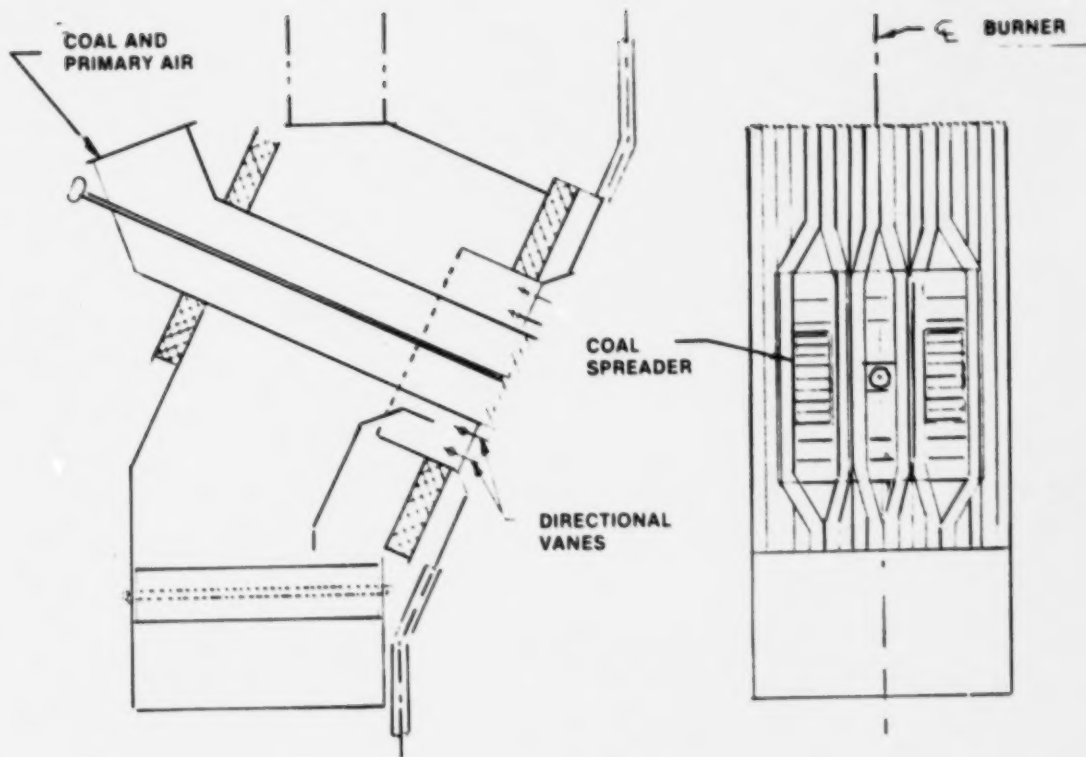


Figure 14 Riley Directional Flame Burner

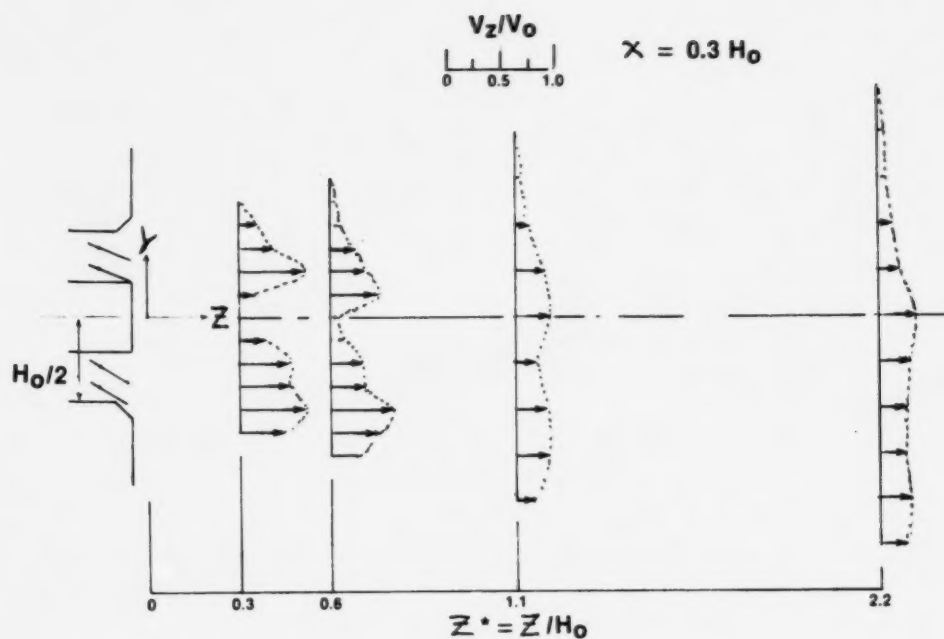


Figure 15 Measured Directional Flame Burner Axial Velocity Profiles
Along a Vertical Plane in Front of the Coal Nozzle

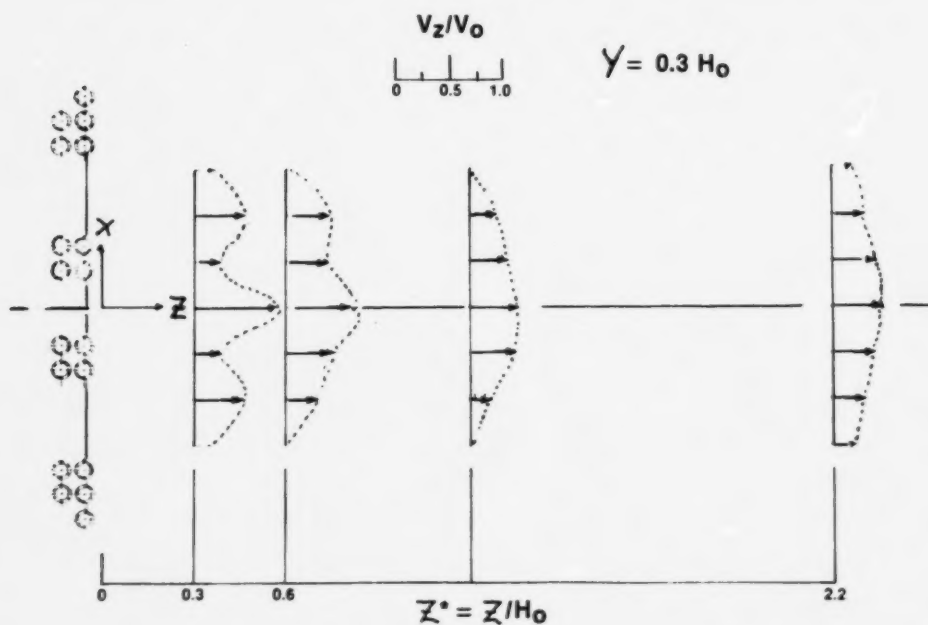


Figure 16 Measured Directional Flame Burner Axial Velocity Profiles
Along a Horizontal Plane Below the Coal Nozzle

94% LOAD (350MW)
 17% EXCESS AIR
 DIRECTIONAL VANE SETTING NO. 7

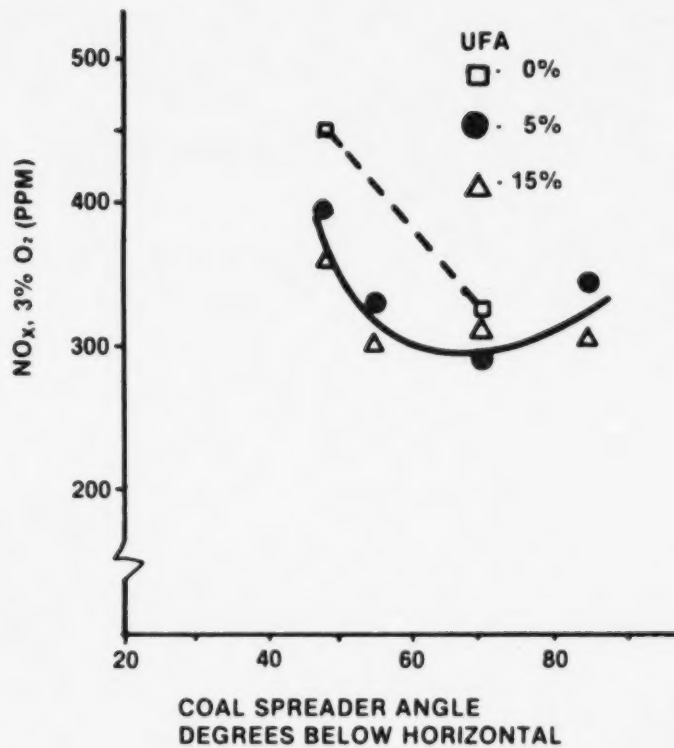


Figure 17 The Effect of Coal Spread by Angle and Underfire Air on TURBO® Furnace NO_x Emissions

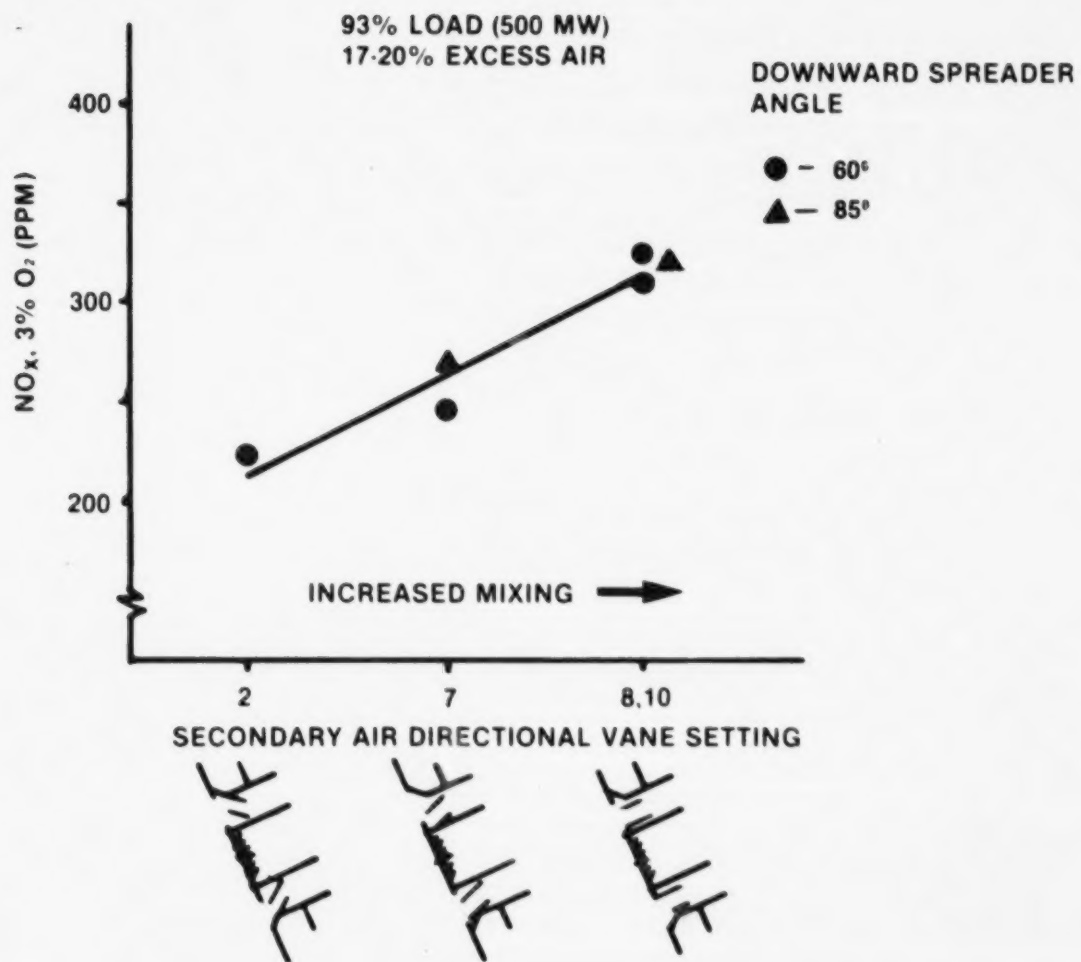


Figure 18 The Effect of Directional Air Vane Position
on Unstaged TURBO® Furnace NO_x Emissions

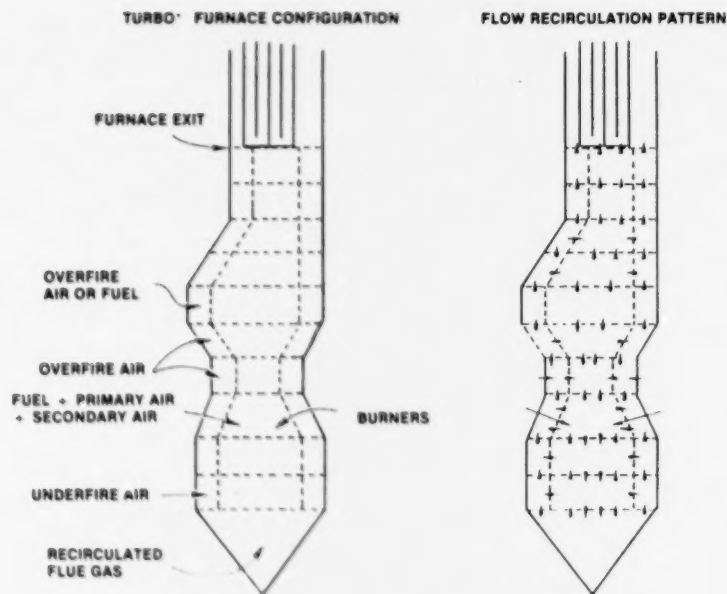


Figure 19 Riley Multi-Zone Furnace Model

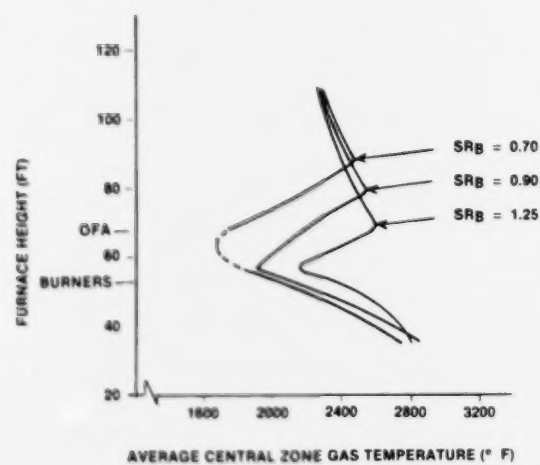


Figure 20 TURBO® Furnace Temperature Profiles, Staged Combustion Study

TABLE 1. SUMMARY RILEY CIRCULAR BURNER
CHARACTERISTICS

FLARE BURNER

- Single or Dual Register
- Pre-NSPS
- High Intensity-Rapid Mix

CONTROLLED COMBUSTION VENTURI BURNER

- Single Register
- Venturi Nozzle/Conical Spreader
- Flare Burner Outer Dimensions
- Delayed Mix

DISTRIBUTED MIXING BURNER

- Dual Register
- Venturi Nozzle/Conical Spreader
- Independent Flow and Swirl Control
- Flow Metering
- Tertiary Air Ports

TABLE 2. FURNACE AND FLY ASH ANALYSIS
CILCO DUCK CREEK 1

Burner	Test Condition	Loss on Ignition, % by Weight		
		Bottom Ash	Economizer Ash	Precipitator Ash
Flare	0% FGR	0.1	0.4	1.9
	20% FGR	2.2	1.7	5.2
CCV	Unstaged	4.2	2.2	5.2
	UFA	5.4	0.65	7.4

FOSTER WHEELER'S LOW NO_x COMBUSTION PROGRAM
STATUS AND DEVELOPMENTS

By:

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ABSTRACT

Foster Wheeler Energy Corporation has developed, and is continuing to advance the state of the art of, internally staged low NO_x burners. These produce low emission levels without using overfire air or tertiary air ports. Currently, the standard commercial offering is the Controlled Flow/Split-flame burner which consistently achieves NO_x levels 60% below turbulent burner emissions in both retrofit and new unit operation. A fuel-staging burner concept, investigated in the mid-70's but not commercialized, is now being evaluated for its potential to enhance the NO_x performance of the commercial burner.

Internally staged burners are advantageous because flame shapes are similar to those of older turbulent burners, thereby allowing high capacity low NO_x burners to be used. Field experience has now been obtained over the capacity range which has been the historical norm for pulverized coal firing: 35 to 300 million Btu/hr.

LOW NO_x STATUS

The most direct method for controlling NO_x is by some form of staged combustion. It is well known that cooler, staged flames reduce thermal NO_x, while substoichiometric conditions reduce fuel NO_x. The method formerly used to control burner stoichiometry involved firing the coal with substoichiometric air quantities at the burner and completing combustion with staging ports introducing the remaining air into the combustion process.

Foster Wheeler Energy Corporation has chosen to utilize the concept of internal burner staging* as opposed to delayed combustion (long) flames or external staging (tertiary staging ports). Two low NO_x burners which achieve large reductions in NO_x without external burner staging have been developed. The first generation^x design is the Controlled Flow burner, which is a dual register type capable of achieving about 40% lower NO_x levels than were

emitted by pre-NSPS turbulent burners. The second generation Controlled Flow/Split Flame burner produces NO_x levels over 60% lower than pre-NSPS designs.

Figure 1 summarizes the NO_x reduction effect of the latter burner design. Uncontrolled emissions are NO_x from pre-NSPS units equipped with turbulent burners. Typical low NO_x burner-equipped boiler emissions are shown for comparison. In both cases, NO_x is plotted as a function of heat input to the furnace, expressed as Burner Zone Liberation Rate.

The Controlled Flow and Controlled Flow/Split-flame are similar (Figure 2), the coal nozzle being the major difference. The following functional description outlines the burner's relevant features:

Secondary Air Control

A series-register arrangement, common to both designs, allows simple burner controls to be used. The inner register, which regulates the degree of swirl around the coal nozzle, is controlled by a manual drive since continuous adjustment is not required. The outer register is controlled by a standard electric drive for operation as "closed", "ignite", and "operate" positions. The register arrangement divides the secondary air into two concentric streams which independently vary swirl. The secondary air flows axially into the furnace with almost no component directed radially inward, toward the burner centerline. Two registers permit the mixing rate between the primary and secondary air streams and the rate of entrainment of furnace gases to be controlled.

Secondary Air Balancing

In order to maintain low levels of excess air while minimizing CO, unburned carbon and slag formation, it is advantageous to attain a balanced secondary air flow to all burners. Foster Wheeler achieves this by measuring the pressure drop across the perforated plate air hood, obtaining an index of the secondary air flow to each burner. The flows are then balanced by positioning the axially movable sleeves, which optimizes the secondary air distribution both vertically and horizontally in the windbox. The air hood also improves secondary air distribution around the periphery of the burner to minimize unwanted turbulence.

Split Flame Coal Nozzle

Coal is injected into the furnace through an annular nozzle which has been modified to separate the coal into concentrated streams, each of which forms

*Internal staging can be defined as adjusting the fuel/air distributions within a burner, operated at normal excess air, within the throat, such as to substantially decrease NO_x emissions without appreciably lengthening the flame.

an individual flame. Four streams are indicated in Figure 2, but the number is a design variable.

The split-flame nozzle minimizes mixing between the coal and the primary air. The combination of the concentrated coal streams and the staged secondary air produces near-throat flame stoichiometries in the 60 to 70 percent range up to about two throat diameters into the furnace. At that point, the swirling secondary stream from the outer annulus, containing the remainder of the combustion air, combines the flames and provides sufficient mixing to ensure adequate carbon burnout. Uniform distribution of coal about the periphery of the annular passageway is attained, as with pre-NSPS burners, by use of the tangential coal inlet. There is no undesirable roping of the coal.

The basic Controlled Flow burner employs a tapered annular nozzle instead of a split-flame nozzle. The inner sleeve tip is axially movable, thereby providing a means for varying the primary air velocity while primary air flow is maintained constant. This velocity adjustment is used to optimize the primary air/secondary air velocity ratio which minimizes shear-induced turbulence.

The flows from both the Controlled Flow and the Controlled Flow/Split-flame burners are axial and symmetrical about the burner axis. The only flow-induced turbulence is that which is deliberately provided by register swirl setting. This produces early staging of the flames with a minimum of unintentional mixing between the fuel particles and the combustion air.

In conjunction with the CF/SF low NO_x burners, Foster Wheeler is also offering the Boundary AirTM system as a means of minimizing slag formation and tube wastage. This system, shown schematically in Figure 3, produces an oxidizing atmosphere along the furnace waterwalls by injecting a relatively small portion of the combustion air into the hopper and along the lower side-walls. A further benefit of Boundary AirTM is that it maintains the oxidizing atmosphere along the sidewalls regardless of unit operating mode, load, or number of pulverizers in service. Once adjusted, during the boiler's initial shakedown, no further adjustments to this system are needed.

Similarity to the Pre-NSPS Burner

After the low NO_x burner's three manual adjustments are made, inner register setting, coal nozzle velocity, and air hood sleeve are locked. The burners then operate in a manner identical to a pre-NSPS intervenor burner. No additional controls are required beyond the existing outer register drive. There are no feedback systems interlocked with the pulverizers and no continuous air flow controllers. Mills are taken in and out of service in exactly the same manner as on pre-NSPS boilers.

The combination of the CF/SF low NO_x burner and Boundary AirTM provide a passive means of maintaining low NO_x levels. And, since a common windbox may be used, the Foster Wheeler low NO_x combustion control system can be retrofitted to existing units with no need for additional ductwork or structural modifications.

The CF/SF Burner: Field Test Results

The CF/SF burner is the heart of the NO_x reduction system and achieves 60% reduction without the benefit of other NO_x control features. The burner is currently installed on two large utility boilers in the U. S. One is the 350 MW San Juan #1 single wall-fired unit burning a high ash sub-bituminous coal; the other is a 525 MW opposed fired unit burning a high moisture western sub-bituminous coal. Both are post NSPS units originally designed for a conventional burner and were retrofitted with the CF/SF burner. The smaller unit has a pre-NSPS sized furnace and originally operated with a conventional burner before being retrofitted. The larger boiler was retrofitted during the final construction phase and was never operated with the conventional burner. Emissions of NO_x from these two units are shown in Figure 4 and, as can be seen, emission levels below 0.4 lbs/10⁶ Btu are achieved. The difference in controlled emissions is explained by differences in firing method, furnace heat liberation and coal properties. In combination with the CF/SF burner, the 350 MW unit had a portion of the Boundary AirTM system and the 525 MW unit had the entire Boundary AirTM system.

Prototype development information was presented at the last NO_x Symposium. It is, however, instructive to compare the prototype results with the field data. Prototype testing was initially performed on a four-burner 125,000 lb/hr industrial boiler (36 million Btu/hr per burner) and later on a 50 million Btu/hr single burner test facility. A comparison of the effectiveness of the CF/SF burner on the respective boilers and the latter facility is also shown in Figure 4. Similar NO_x reductions were achieved even though the burner size ratios were 6:1. Unit geometries are quite different. Figure 5 shows a section of the smaller unit.

It should be noted that the San Juan #1 unit has a furnace depth of 34 feet and is equipped with burners with a maximum liberation rate of 285 million Btu/hr. Burner spacings are 10 ft vertically and 9'9" horizontally. All three dimensions were based on pre-NSPS boiler design parameters which were developed for short-flame turbulent burners. The fact that there is no flame impingement on any surface and that steam conditions did not change after low NO_x burner retrofit is ample evidence that the CF/SF burner is an internally-staged short flame type.

Furnace geometrical differences generally cause a substantial difference in NO_x emissions. A horizontally opposed fired boiler equipped with turbulent burners will emit NO_x levels 20 to 30% below a single wall fired unit because of flame interactions_x. As shown in Figure 1, the installation of the Foster Wheeler CF/SF burner produces NO_x levels substantially below those for uncontrolled units. This is due to the burner only.

The CF/SF burner has been successfully applied to large western sub-bituminous coal fired boilers, retrofit and new, but has not been tested on a large eastern bituminous fired boiler. Testing, on industrial and pilot sized units, has indicated that this burner reduces NO_x emissions equally regardless of the fuel type. In the units that have been tested, operation and reliability have not been affected. Although the burner hardware is more complex than that on a pre-NSPS unit, the operation is no more complex once

system optimization is completed. During the startup of the unit, the burners are adjusted for minimum NO_x and CO, while flame stability and combustion efficiency are maximized. Once these adjustments are made, the burner management system controls combustion.

Furnace slagging is aggravated by NO_x controls that use substoichiometric firing. The primary reason for this is the effect oxidizing and reducing conditions have on the ash softening temperatures. Reducing conditions can lower the ash softening temperature by 200 to 300°F. Substoichiometric firing converts the entire combustion zone below the overfire air ports (OFAP) from oxidizing to reducing atmosphere. The prime intent of OFA is to reduce the oxygen available to the fuel-bound nitrogen in the flame and reduce the flame temperature. Under these reducing conditions, the ash softening temperature is lowered. This effect is most significant on eastern bituminous coals. The Foster Wheeler CF/SF burner, in combination with the Boundary Air™ system, should overcome this problem by allowing the burner to operate with normal excess air. Although the burner is operated with normal excess air, the flame is actually sub-stoichiometric and is shrouded by excess air from the outer register. The Boundary Air™ system has been successfully retrofitted to numerous pre-NSPS units, firing high sulfur bituminous coal, to control slag.

Although Foster Wheeler's low NO_x burners can obtain NO_x levels up to 60% below turbulent burner emissions, further NO_x reductions are obtainable with moderate amounts of overfire air. Figure 6 summarizes the effect of staging using overfire air with various types of burners. Due to the potential for slagging and high unburned carbon levels when large amounts of overfire air are used, Foster Wheeler uses no more than 20% overfire air (minimum burner stoichiometry of 96%). NO_x levels as low as 0.25 lb/million Btu have been obtained on a 525 MW utility steam generator (CO was about 30 ppm) as shown in Figure 4. Such low levels may not be achievable with all coals due to variations in quality and nitrogen content with coal type.

Low NO_x Combustion System Summary

The Foster Wheeler low NO_x system differs from other methods, either developed or under investigation by others, in the following ways:

- The Foster Wheeler system is based on the Controlled Flow/Split Flame (CF/SF) low NO_x burner which has been successfully operated over the entire burner capacity range of pulverized coal steam generators (35 to 300 million Btu/hr).
- The CF/SF burner is an internally staged design which has a short low NO_x flame, comparable to the flame envelope of pre-NSPS turbulent burners. In contrast, other designs use delayed mixing flames which are 3 - 4 times longer.
- Foster Wheeler's system does not rely on furnace staging (use of overfire air or tertiary air ports) so that the lower furnace is always at oxidizing conditions. However, overfire air can still be used where necessary, to achieve an additional 25-30% NO_x reduction.

- There are no active feedback mechanisms or flow controllers required for NO_x control in the Foster Wheeler system. NO_x is controlled in an entirely passive manner.
- After optimization for low NO_x operation, the CF/SF burners operate in precisely the same manner as pre-NSPS equipment: no new controls or flame safety systems are required.
- The system is designed for operation within a common windbox so that no windbox or structural modifications are needed for retrofit applications.
- NO_x reductions of over 60% should be achievable without resorting to furnace staging with overfire air ports or flue gas recirculation.

Foster Wheeler offers the commercially proven Controlled Flow/Split-flame (CF/SF) low NO_x burner design with Boundary Air™ for prevention of furnace wall slagging and tube wastage. The system is standard equipment on all new boilers and is offered as retrofits to existing units.

FUEL STAGING LOW NO_x BURNER

Foster Wheeler has determined that the presence of a pilot flame, located coaxially within the main coal flame, can reduce NO_x emissions. Inserting a low load burner within the CF/SF burner can yield lower NO_x levels than are achievable with the low NO_x burner alone.

Functionally, fuel staging is a means of internally staging a burner to produce a very substoichiometric flame, along the burner's axis, which is surrounded by another flame (from the main burner). Figure 7 is a schematic representation of this concept. The internal flame produces partially burned products which then pass through the main flame. This yields a re-burning effect similar to the in-furnace de-NO_x system. However, the former takes place within each flame while the latter requires severe staging of the entire combustion zone (all burners are at severe reducing condition).

The NO_x reduction potential resulting from the pilot flame within a coal fired flame has been investigated on a number of occasions by using an oil fired class 1 ignitor, since up until now a coal fired pilot has not been available.

Emission reductions of NO_x in the range of 20-25% have been achieved in the tests with class 1 oil ignitors. Figure 8 summarizes the field data. Note that the NO_x reduction with turbulent burners was larger when overfire air ports are open, implying a synergistic effect with low NO_x firing. Larger reductions were achieved with the low NO_x burner further confirming the effect. The internal fuel staging becomes more effective when added to the low NO_x or as the furnace becomes increasingly staged as overfire air ports are opened.

Fuel-Staging Burner - Developmental Status

Foster Wheeler has been investigating fuel-staging for NO_x control since the

mid-1970's. Prior to this, dual range coaxial coal burners had been evaluated for their potential to increase burner turn-down range and low load stability. More recently, the high cost of using oil as a startup and stabilization fuel for coal-fired boilers has made coal-based low load systems economically attractive. Foster Wheeler has, therefore, expanded the fuel-staging concept to include low load firing capability. A small coal burner replaces the traditional class 1 ignitor on the burner's axis and is continuously operated so as to provide NO_x reduction at higher loads.

The system's low load capability is based upon ignition of a fuel-rich coal stream with a small (about two million Btu/hr) oil or gas lighter. It is estimated that auxiliary fuel use can be reduced by up to 95%.

Figure 9 summarizes the system concept: the primary coal conduit feeds a particulate separator which concentrates the coal which is then fed to the central low load burner. The primary coal supply is maintained approximately constant. When load increases are required the additional coal is supplied to the main burner from the secondary coal conduit. Thus, wide burner turn-down is achieved concurrently with the flame-within-flame concept shown in Figure 7.

Figure 10 is an isometric view of the CF/SF high capacity low NO_x burner with the centrally located low load burner. Coal from the particulate separator exits the low load nozzle on the burner axis and is then re-entrained by the primary coal conduit's air. A strong recirculation zone is set up by the swirler located in the primary air stream. This central flame is sub-stoichiometric so maximum flame stability is achieved with a minimum of heat loss, thereby maximizing combustion efficiency.

Although the Fuel-Staging Burner has not yet been field tested with coal, the effect on NO_x emissions can be estimated by pro-rating the data obtained from oil-firing.^x Figure 11 compares NO_x reductions from the first generation Controlled Flow burner and second generation Controlled Flow/Split-flame burner with the predicted estimates for the Fuel-Staging design. NO_x reductions of up to 85% may be achievable on new boilers (as compared to expected emissions on these boilers if pre-NSPS turbulent burners were to be used). NO_x reductions on existing pre-NSPS boilers with high heat release rates, may^x not be as large.

Since the Fuel-Staging low NO_x burner incorporates low load firing capability, which can provide significant^x reductions in auxiliary fuel consumption, there can be major cost savings when existing boilers are equipped with this system. Figure 12 contains data on the costs of NO_x removal as a function of amount of oil saved per year (expressed as hours/year the original class 1 ignitors are not fired) and parametrically in years of remaining boiler life. It can be seen that there is a wide range of conditions for which there is a net savings as a result of implementing NO_x controls with Foster Wheeler's Fuel-Staging low NO_x system.

Preparations are now in the final stages for a full-scale field test of this concept on a large utility steam generator equipped with burners which are rated at 250 million Btu/hr each. Information will be available by mid-1983.

IN-SITU SULFUR CAPTURE

The concept of capturing sulfur during the combustion process has been investigated since the late 1960's. Fundamentally, this involves injecting a sorbent into the boiler's radiant zone to effect sulfur removal. Early attempts involved boilers with high heat release rates and turbulent burners. These resulted in low capture rates primarily due to dead-burning of the sorbent (limestone).

More recently, emphasis has been placed on combining sorbent injection with low NO_x combustion systems to take advantage of the lower peak flame temperatures and better control of fuel/air mixing rates, as compared to pre-NSPS equipment. Results have been significantly better than the original attempts, although considerable developmental effort remains to be undertaken. It is unlikely that in-situ sulfur capture will be competitive with scrubbers for meeting NSPS SO_2 emission limits. However, this technology should be applicable in those cases where lower capture rates are acceptable.

Foster Wheeler began investigating in-situ sulfur capture over a decade ago and tested a means of sorbent injection on an 80 MW utility steam generator. The boiler is equipped with eight (8) turbulent pre-NSPS burners and does not have any NO_x controls. Figure 13 is a map of sulfur capture against full sulfur content and calcium-to-sulfur mole ratio (Ca/S) and compares recently published EPA-sponsored data to earlier data taken by Foster Wheeler. The former is from single Distributed Mixing Burner tests with two types of bituminous coal, while the latter is from Foster Wheeler's field testing with another bituminous coal. There is considerable agreement between the data groups, although there is little commonality between the test systems.

Since the Foster Wheeler system was tested without the benefit of a low NO_x combustion system, it is believed that there is room for considerable improvement. Combining Foster Wheeler's low NO_x combustion system with the sorbent injection system should yield sulfur capture ratios in excess of 50% at Ca/S of about 2.0.

SUMMARY

Foster Wheeler has continued to gain field experience with the Controlled Flow/Split-flame low NO_x burner. NO_x levels of about $0.4 \text{ lb}/10^6 \text{ Btu}$ have been routinely achieved on 375 MW and 525 MW steam generators without using overfire air or flue gas recirculation. The latter unit has achieved levels below $0.25 \text{ lb}/10^6 \text{ Btu}$ when overfire air is used. This system has been in commercial field operation since 1979 and has been the standard offering on new steam generators.

The CF/SF system is retrofittable to existing units on a "plug-in" basis to provide improved combustion performance as well as low NO_x emissions.

A third generation low NO_x design, the Fuel-Staging burner, is undergoing development. This system, in addition to yielding further NO_x reduction capability, will also be designed for low load burner use. As such it will

reduce auxiliary fuel consumption by up to 95%. In many cases this system will result in a cost saving for NO_x control as expressed in dollars per ton of NO_x removed. Foster Wheeler's aim, with this technology, is to attack two problems with one burner design: NO_x emissions, and auxiliary fuel consumption.

Foster Wheeler is also investigating in-situ sulfur removal by combining the CF/SF burner with a sorbent injection system which was field tested on an 80 MW utility boiler. Test results, without low NO_x burners, showed SO₂ reductions of 40-60% at Ca/S between 2 and 4. Significant improvement is expected with the CF/SF low NO_x combustion system.

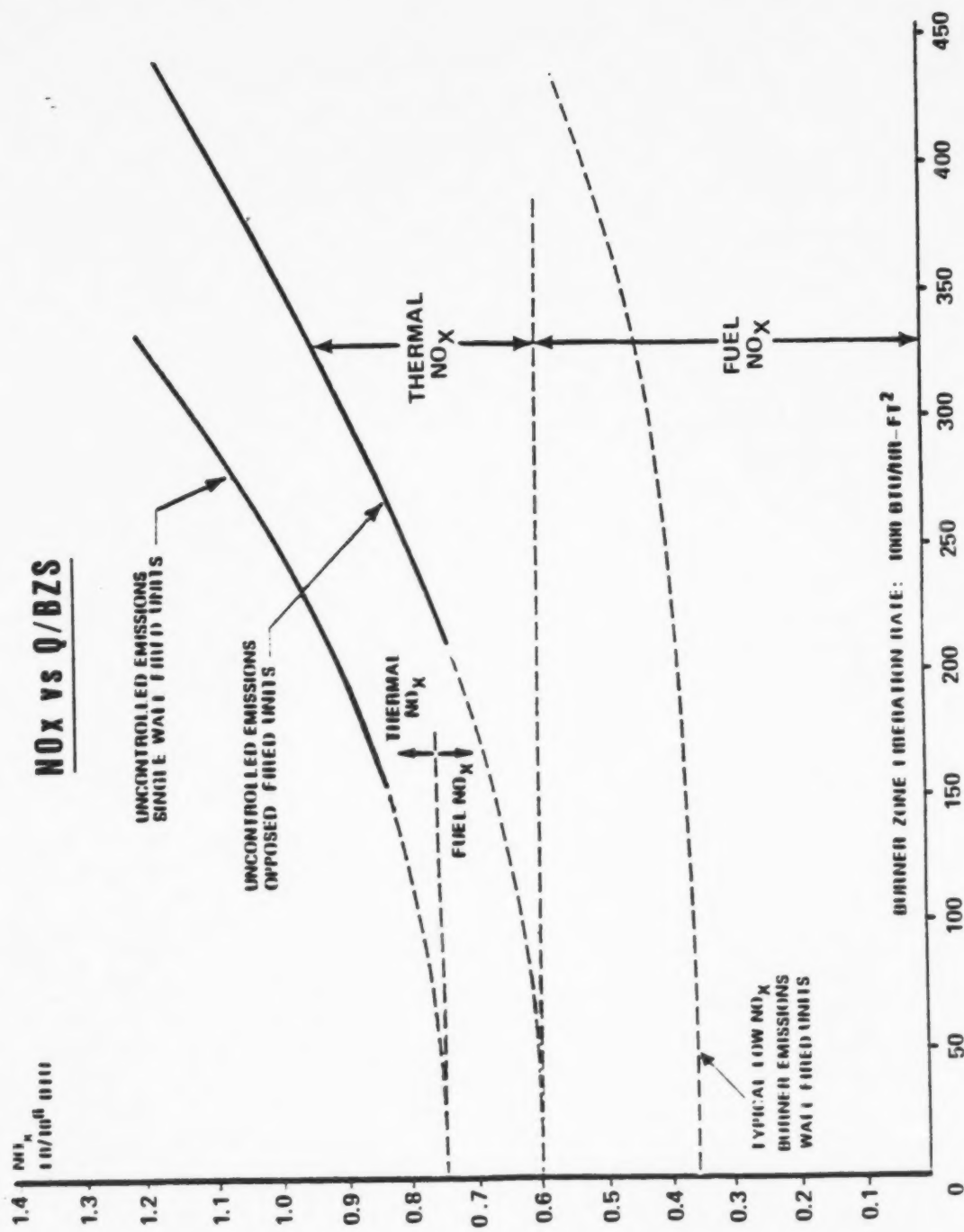
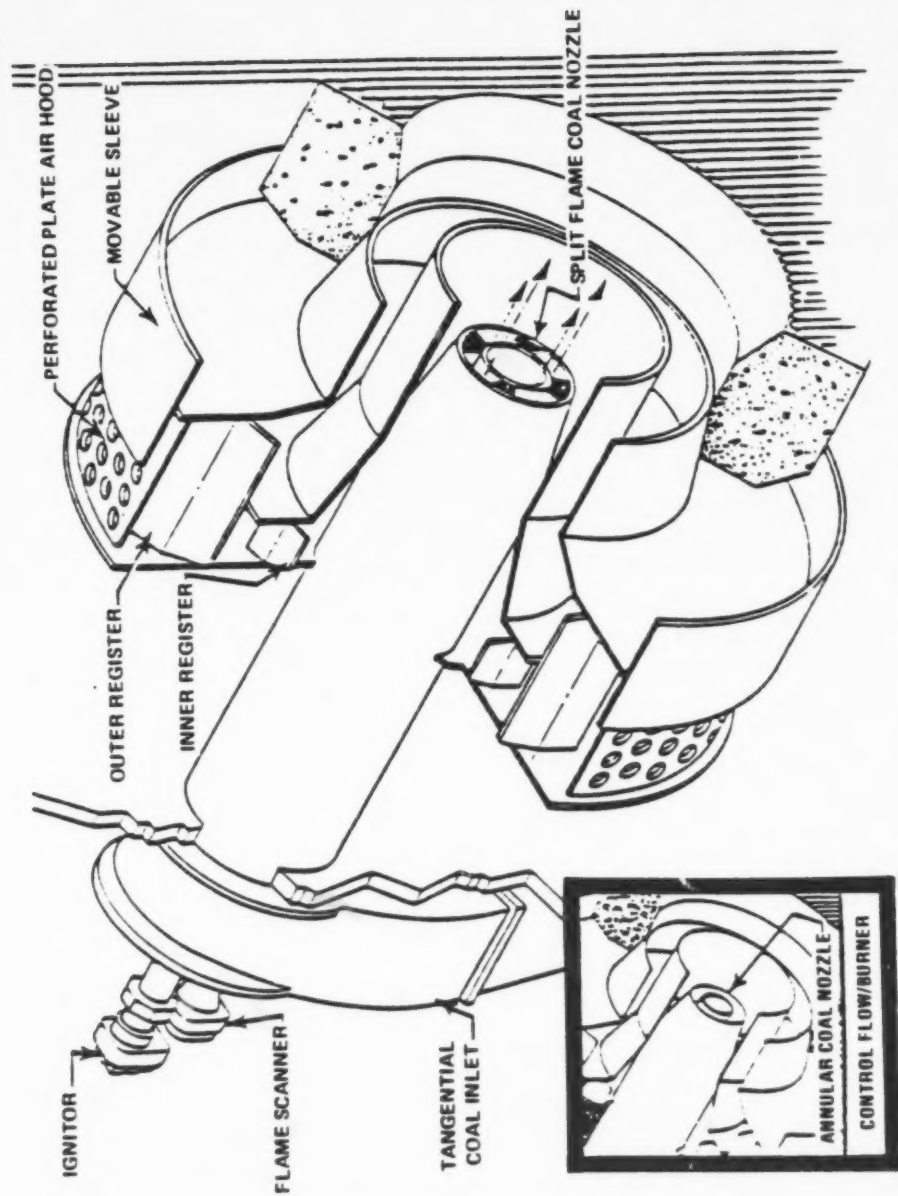


Figure 1.



CONTROLLED FLOW/SPLIT FLAME LOW NO_x BURNER

Figure 2.

BOUNDARY AIR SYSTEM

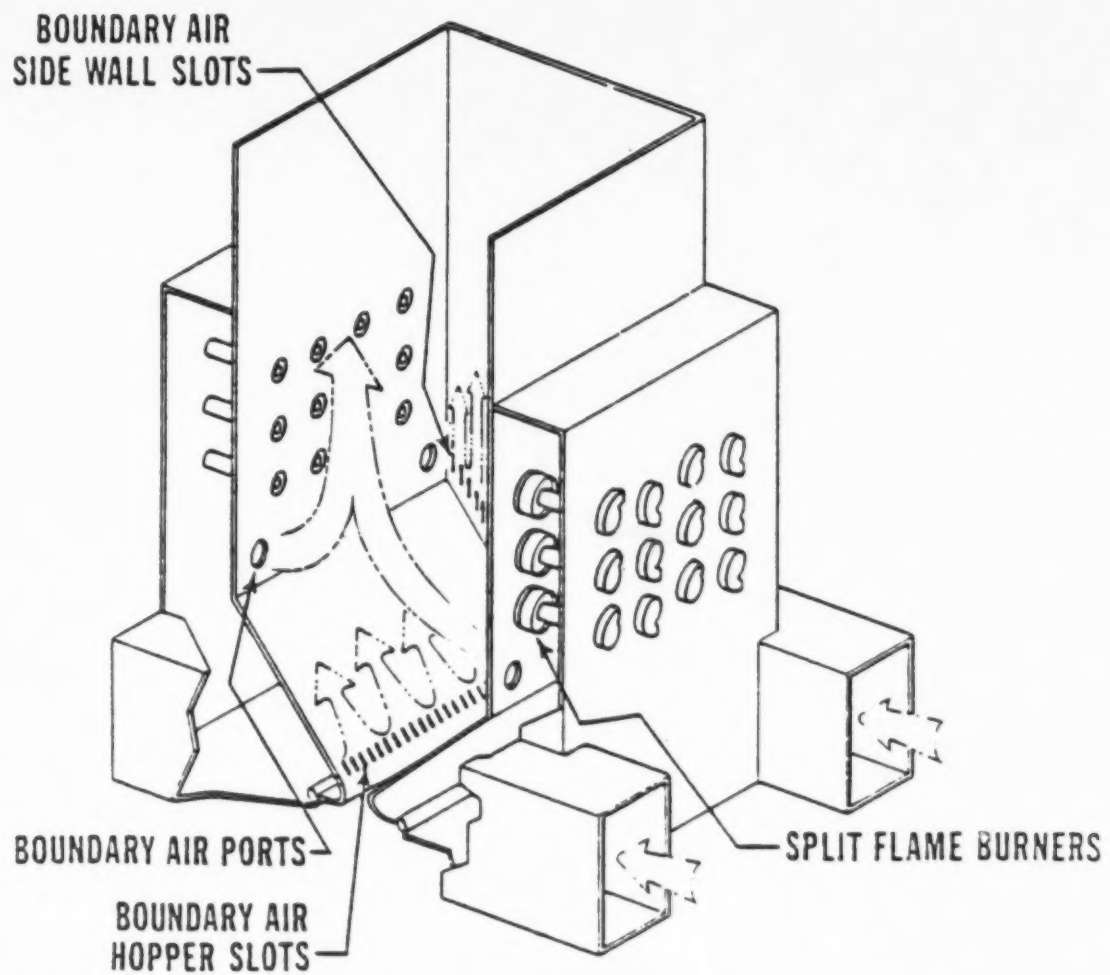


Figure 3.

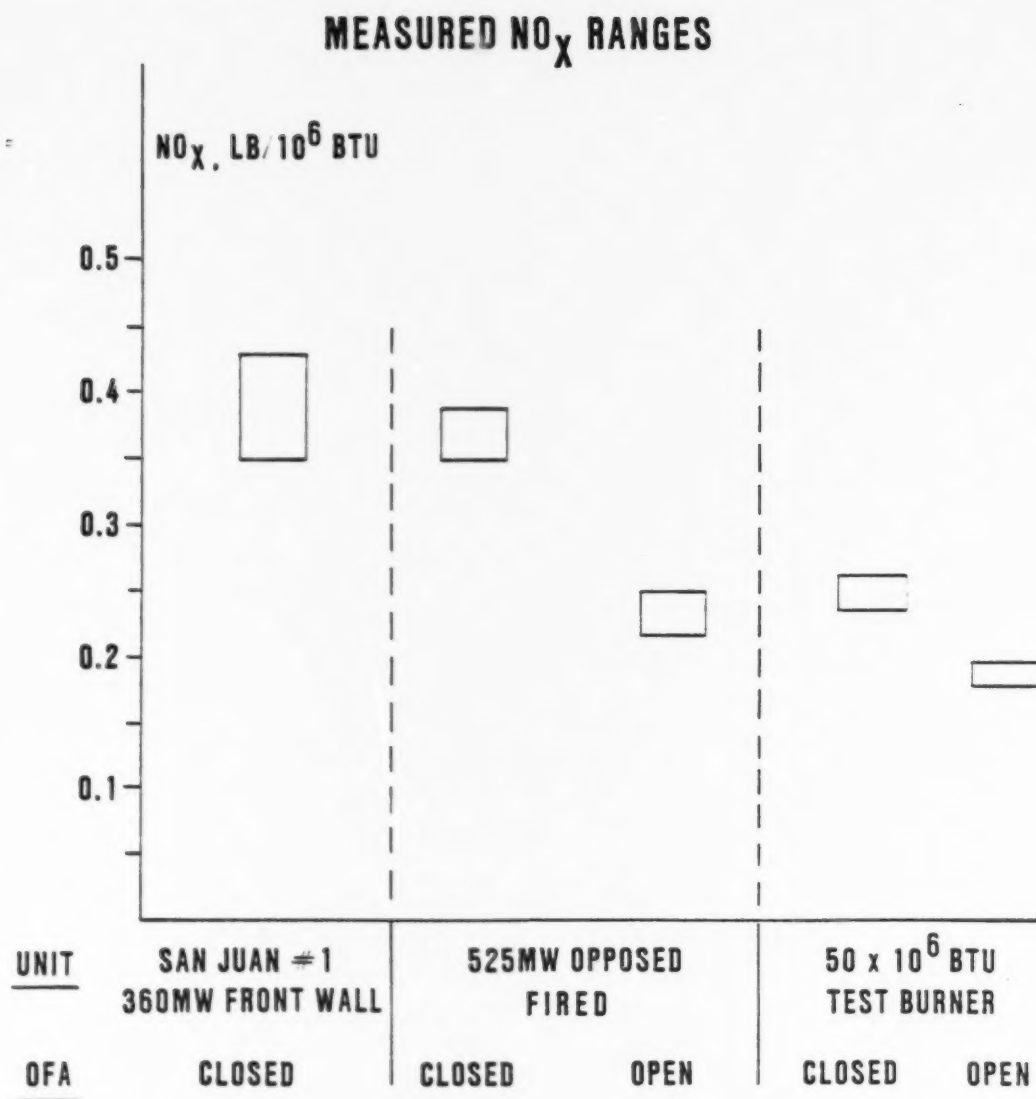


Figure 4.

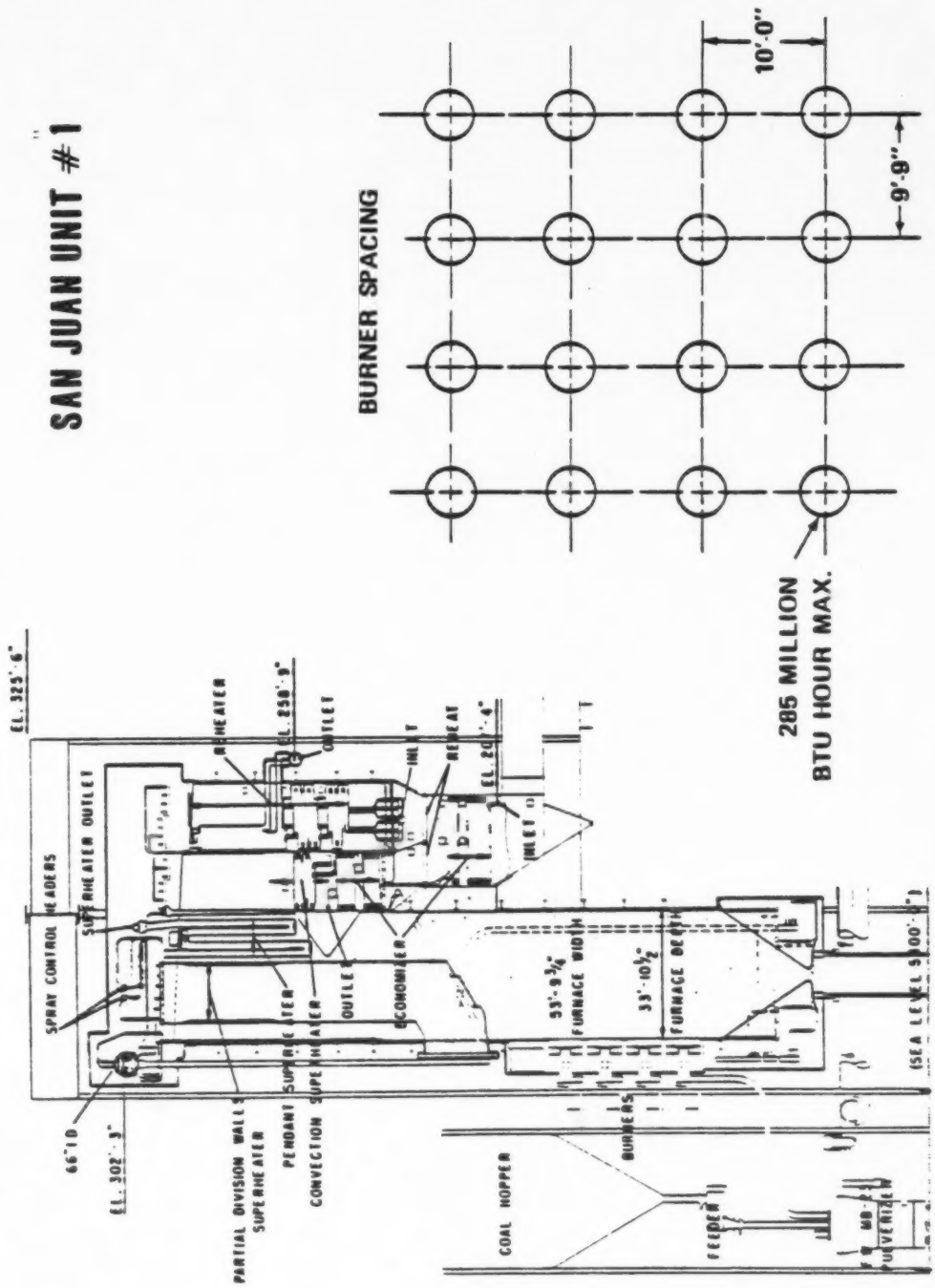


Figure 5.

NO_x LEVELS WITH STAGING

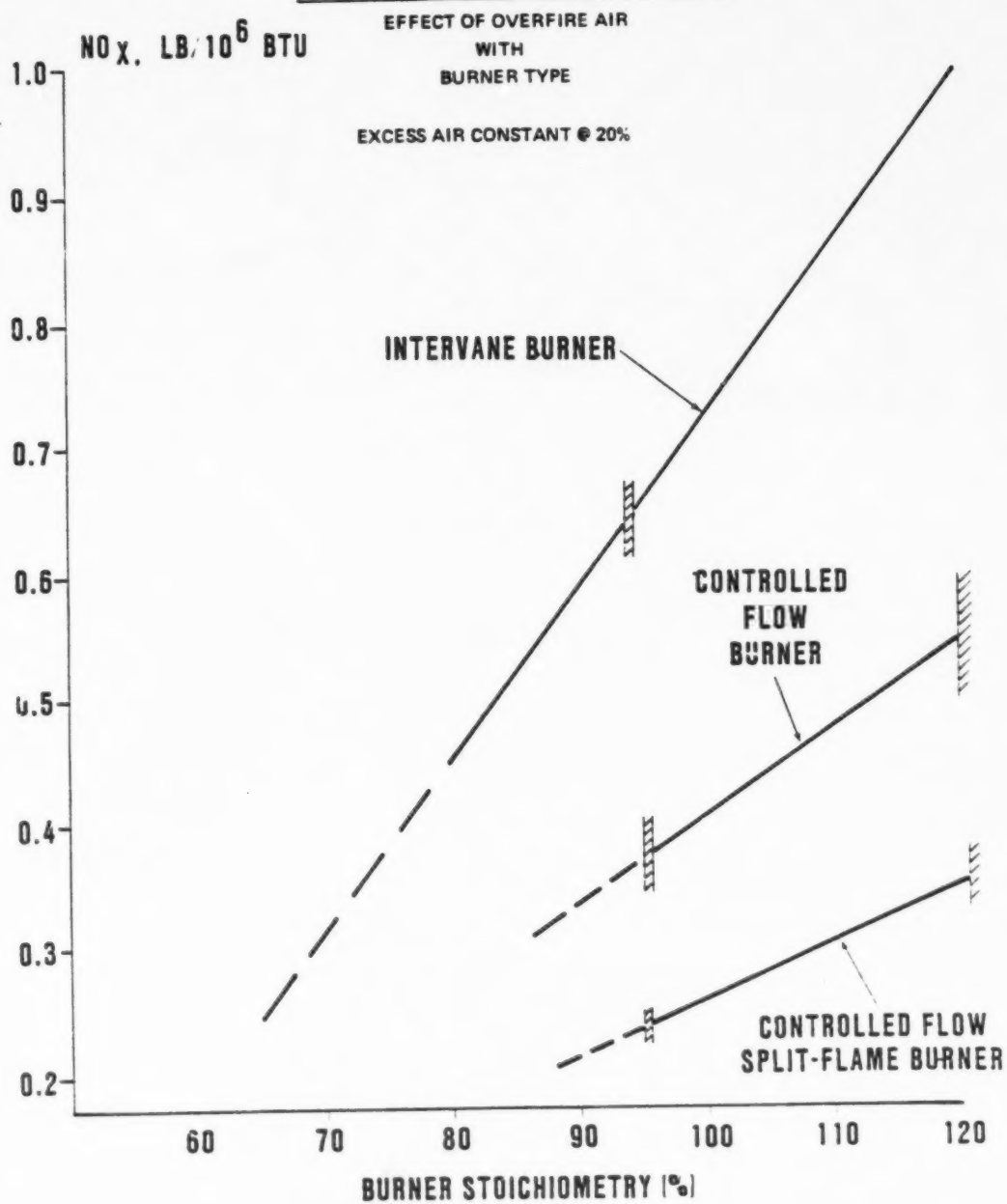


Figure 6.

**FUEL-STAGING LOW NO_x BURNER
1975 CONCEPT**

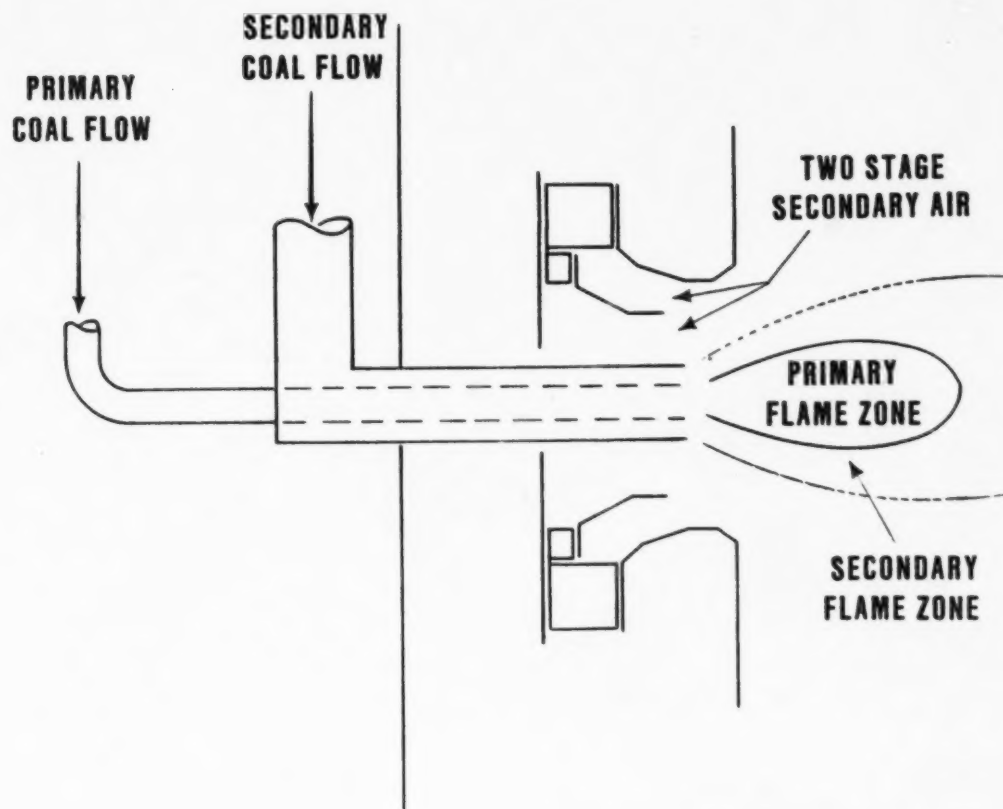


Figure 7.

FUEL - STAGING EFFECT ON NO_x

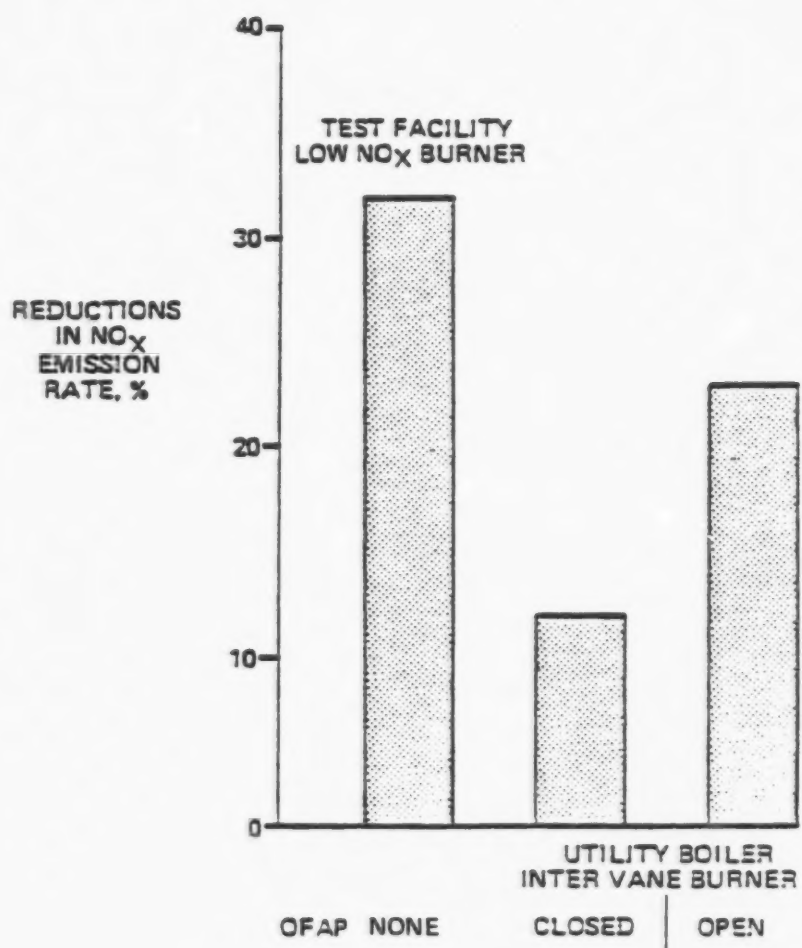


Figure 8.

FUEL STAGING COAL BURNER SYSTEM

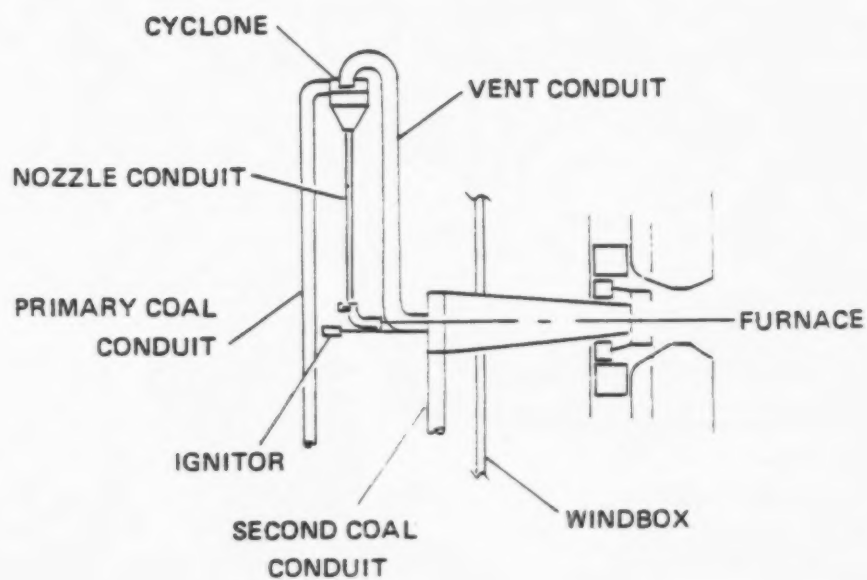


Figure 9.

FUEL STAGING LOW NO_x BURNER

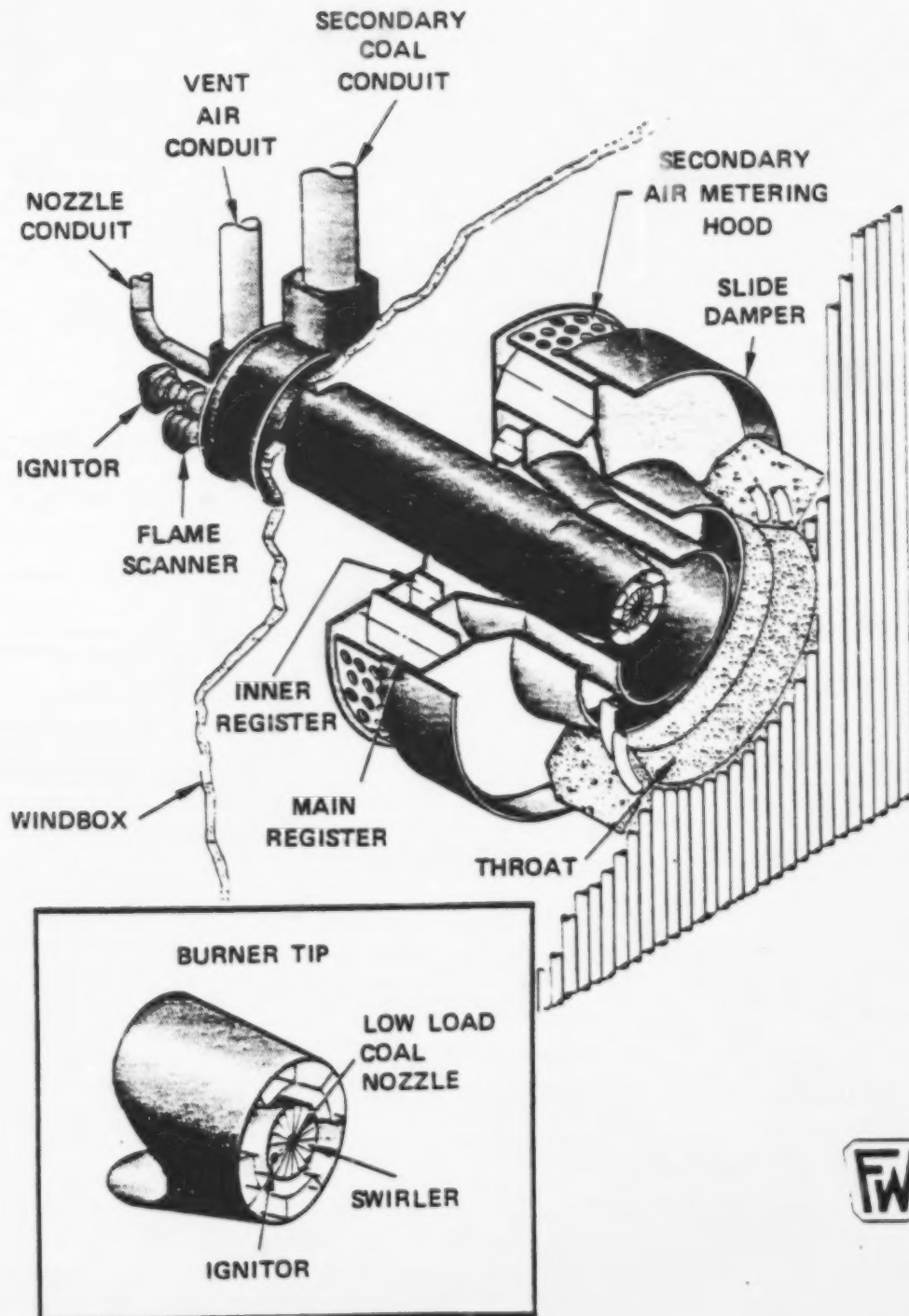


Figure 10.

NO_x REDUCTION COMPARISON

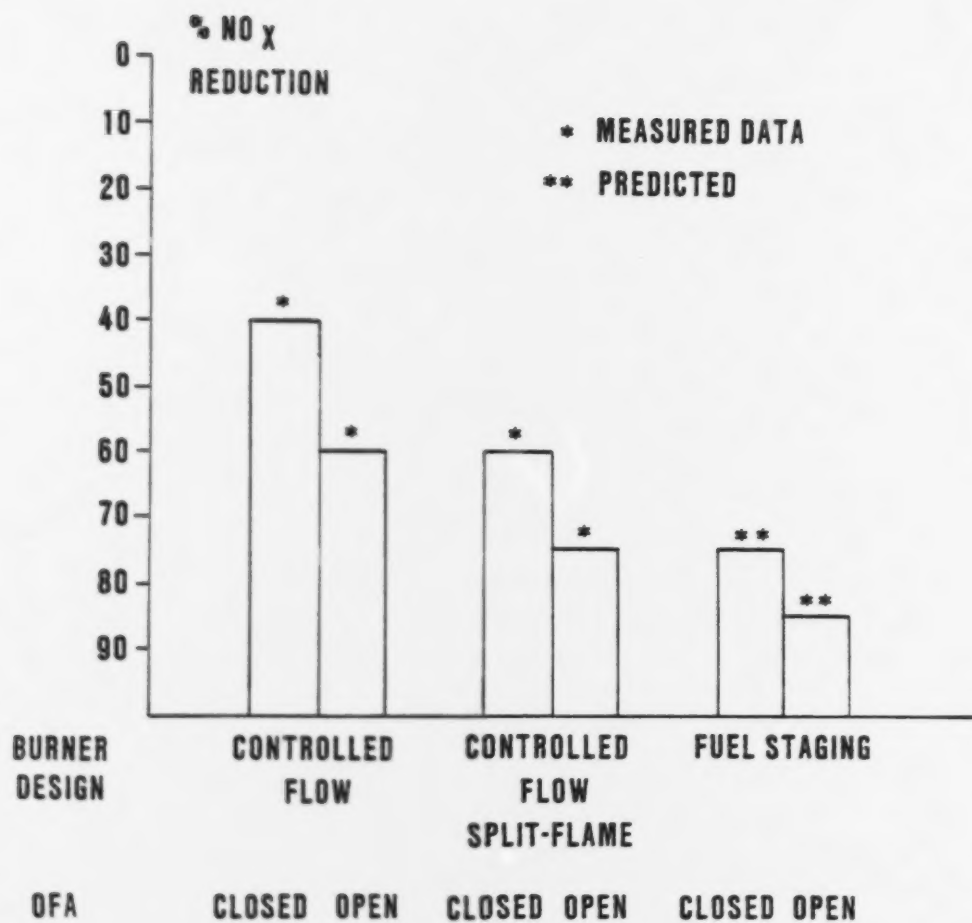


Figure 11.

FUEL STAGING BURNER NO_x REMOVAL COSTS

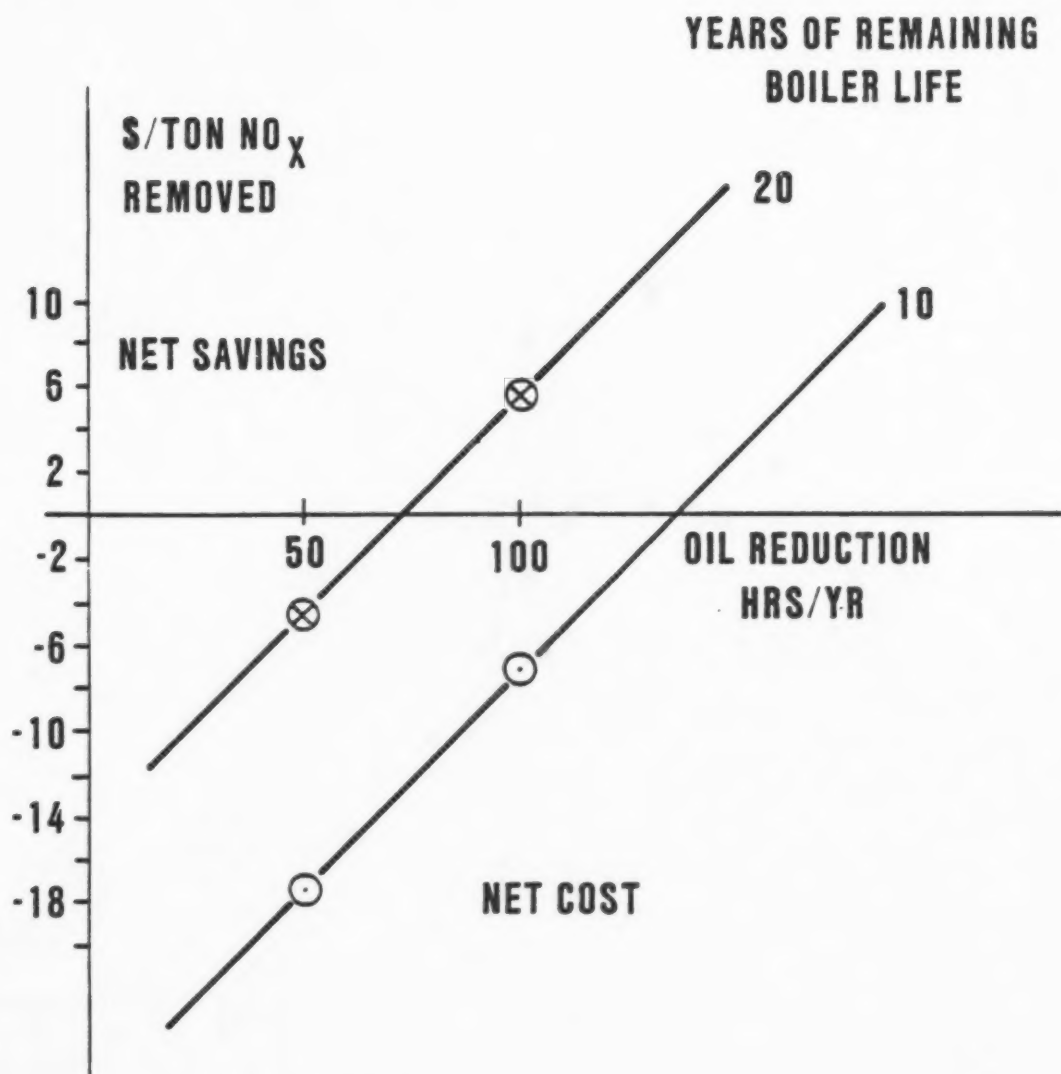


Figure 12.

IN-SITU SULFUR CAPTURE

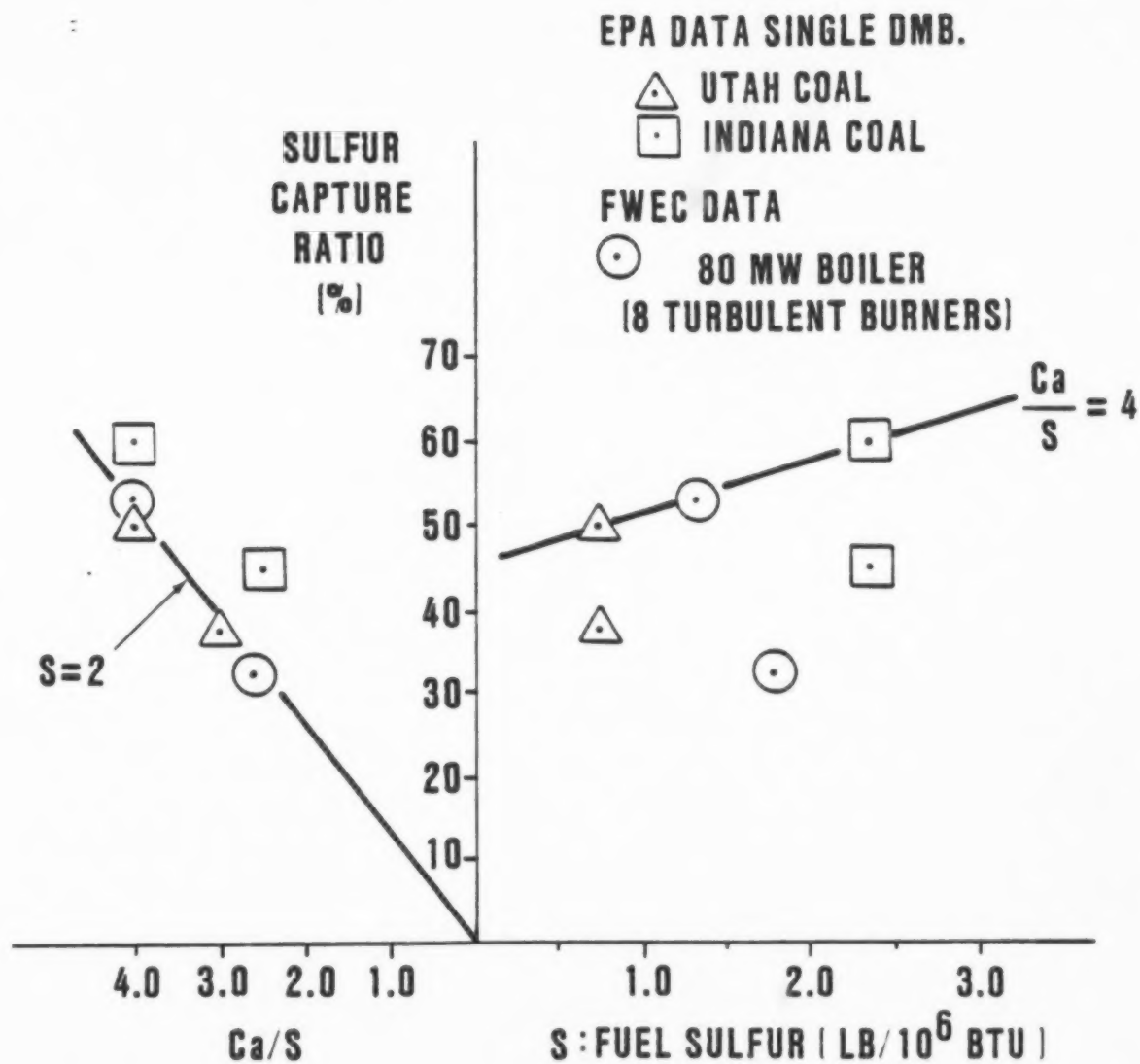


Figure 13.

FOSSIL STEAM GENERATOR NO_x CONTROL UPDATE

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ABSTRACT

Since the third NO_x Control Seminar of 1980, additional information has been gathered concerning actual NO_x emissions from fossil-fuel power plants equipped with B&W Dual Register Burners/Compartmented Windbox furnace systems. These systems use a wide range of both bituminous and subbituminous coals. The field results, from actual units firing coal and oil, have demonstrated NO_x reduction of up to 60 percent compared to units without NO_x control.

B&W's future low-NO_x R&D direction is summarized as well as the laboratory work done on the High Nitrogen Liquid Fuel burner (HNLFF). Also, the most recent laboratory-facility additions (a new 5×10^6 Btu/hr furnace, atomization facility and laboratory ashing furnace) are described. These additions will permit more extensive small-scale work. Retrofit concepts for the pre-NSPS coal-fired units, both cyclone and pulverized coal, are presented. Furthermore, a summary is given of B&W's future low-NO_x R&D direction for meeting the increasingly restrictive NO_x-emission levels.

The Dual Register Burner/Compartmented Windbox System has been commercially applied to all New Source Performance Standard (NSPS) steam generators sold domestically by B&W since 1972. At the last NOx Symposium (1980) it was reported that 26 steam generators representing 15,000 MW of pulverized coal-fired capacity had been placed in service utilizing this system. Now in 1982, the numbers are 34 units and 20,000 MW. This represents 2,000 burners in service and 3,500 shipped in ten years, firing bituminous, subbituminous and lignite fuels (Figure 1). Detailed descriptions covering the laboratory development and initial retrofit of this system can be found in References 1 and 2.

The largest unit to come on stream during the past two years was AEP's Mountaineer #1, a 1300-MW unit with two more 1300's to follow at the Rockport Station in '83 and '85. Typical additions to the B&W data base were in the 600-MW size range; good examples of which are Basin Electric's Laramie River #2 and #3, SWEPCo's Welsh #2 and #3 and Louisville Gas & Electric, Mill Creek #4.

All of our steam generator NOx guarantees were based upon the data generated from the Dual Register Retrofit at the E.C. Gaston Plant, Southern Company's Southern Electric Generating Co.³ The NOx prediction curves generated by that data, correlating heat input per adjusted furnace surface (HA/Sc_1) vs NOx expected for various excess air levels with baseline circular burner, followed up by Dual Register Burner performance, permitted us to offer low NOx systems that could meet the NSPS³. Plotting recent field data on the 15 percent excess air curve generated from that retrofit (Figure 2) indicates that, in retrospect, we were conservative and our risk in making the guarantees was minor. The NSPS was revised in 1979 from 0.7 lbs NOx/10⁶ Btu for all coals, except lignite, to 0.6 for bituminous and 0.5 for subbituminous coals. The B&W low NOx system, though designed for the 1970 NSPS, meets or better the 1979 revised standards without having to go to substoichiometric conditions (two stage) in the furnace. Our system does not require "boundary air" or diversion air/overfire air to meet the NSPS of 1979.

The first Dual Register Burner went into service in 1975. The seven years of operating experience has allowed us to evaluate the system's wear life and mechanical operation. This review has resulted in several revisions to the base burner which include the following: 1) The venture/plug combination has been removed because of marginal coal distribution, severe erosion and high pressure drop. It has been replaced with the conical diffuser, which is cast of wear resistant material, has a lower pressure drop, excellent peripheral coal distribution, and weighs less than 200 pounds. 2) The inner air register has been eliminated because the tangential components of air flow that it produced were subsequently destroyed by the swirl vanes. That register has been replaced with a sliding sleeve to control air flow quantities in that zone. 3) The spin vane operational gearing did give movement problems initially due to fly-ash packing in the gears. A redesigned gear was retrofitted on jobs requiring it and now is the standard. 4) Recently, several coal nozzles on some jobs have been overheating when out of

service on upper level burners. The cause is related to out-of-service compartment cooling air flows lower than recommended. The stainless 12-inch long nozzle was not damaged but some of the carbon steel coal pipe located behind the stainless nozzle has demonstrated overheat and the alloy zone will be extended an additional 6 inches for a total of 18 inches to correct this problem.

Laboratory work on new low NO_x concepts in progress during the past two years has concentrated on developing a short flame low NO_x burner for the smaller industrial coal-fired units and a good low NO_x burner suitable for coal, gas and oil firing. The low NO_x P.C. burner suitable for gas, oil and coal fuels is a joint development under funding and direction of the Stork Boiler Company of the Netherlands. The burner is similar to that developed jointly with Deutsche-Babcock in 1978, at a five-million Btu level (Figure 3). These trials are at the 30x10⁶ Btu level and provide us another laboratory data point to reduce risks associated with the commercial application. This laboratory-developed burner will be applied to a 600-MW unit currently under design.

Our Industrial and Marine Division continues its development of a short flame low NO_x burner suitable for use in small industrial furnaces. The test furnace utilized for these laboratory trials was a FM (Factory Assembled) package boiler rated at 50,000 lbs/steam per hour on oil or gas. It was not designed for coal but performed satisfactorily from a slagging, fouling and carbon utilization standpoint at 60 percent MCR for about 45 days of testing. Three different concepts were tried, all providing near field mixing flexibility and were compared to the two baseline conditions of circular burner (high NO_x) and standard Dual Register (low NO_x). The first trial utilized a revised standard circular burner impeller which we label "Radial Vane Impeller". The second concept labeled "Adjustable Swirl" utilized a movable sleeve to vary the tangential components of secondary air flow. The third concept entitled "Controlled Mix" utilized stationary fixed vanes in a dual-air zone configuration. Air flow splits, inner to outer, were controlled by a sliding sleeve. Results (Figure 4) indicate the "Controlled Mix" burner was the lowest NO_x producer and had the shortest flame. Three coals were tested on each concept and the baselines included eastern bituminous, western bituminous and subbituminous. The "Controlled Mix" burner is currently undergoing field evaluations in a industrial retrofit experiment with encouraging initial results.

Our laboratory work on the Low NO_x Combustor System (LNCS) at the 5 and 40x10⁶ Btu levels is complete under joint EPRI/B&W sponsorship. The concept of a fuel rich (deep staging) first stage, and destruction of NO_x in the second stage, as a function of temperature (Johnson Effect)⁴, has been adequately demonstrated in the laboratory and awaits adequate funding to cover a field demonstration. The cost analysis made in 1980 continues to indicate that combustion modifications are the most cost effective way to go. Selective Catalytic Reduction (SCR) cost estimates lie between 55 and 100 \$/kW capital and 1.7 mils/kWh operational. Thermal deNO_x, although at \$10/kW is a capital bargain compared to SCR,

has high operational costs of 1.2 mils/kWh. The licensor of thermal deNOx indicates that a 30 percent reduction on coal, due to limited coal experience obtained to date, is a level they could guarantee. Capital costs associated with the B&W/EPRI LNCS (a combustion modification) are less than \$15/kW for an 80 percent reduction and operational costs are less than 10 percent of the thermal deNOx.

B&W low NOx coal development goals are summarized in Figure 5. Systems providing up to 80 percent reductions from uncontrolled levels have been described. The system labeled "After-Burning" coupled with LNCS has the potential to effect 90 percent NOx generation reductions when compared to uncontrolled levels. A numerical goal attached to that percent reduction would be the achievement of less than 100 ppm of NOx on a P.C. system (Figure 6).

Laboratory work reported by Babcock Hitachi and others on the IFNR (In Furnace NOx Reduction) or after-burning approach would couple the flexibility of our present compartmented windbox system with the LNCS. The compartmented windbox permits individual pulverizer air control that, in turn, permits the lower burners to operate at a 15 to 80 percent stoichiometry, providing an overall lower furnace first-stage stoichiometry of 0.7 percent. This level has already been laboratory demonstrated for low NOx potential by the LNCS work, and now, by many other investigators. Several of our NSPS steam generators, equipped with compartmented windboxes and OFA ports, could be utilized to field demonstrate the LNCS/after-burning low NOx potential. The after-burning fuel injectors could use traditional primary air coal ratios or dense-phase transport to maintain minimum O₂ levels. Both approaches should be investigated. The delay in scheduling a field demonstration is due to the problem of obtaining financial assistance.

Fuel nitrogen correlations from the extensive field data collected have not correlated well with the NOx emissions measured. Our Research Division had started to develop a fuel nitrogen/temperature correlation, but the data developed by Pershing under IEA funding, correlating the fuel N₂ of 48 worldwide coals with emissions, appeared to be so promising that we will redirect our efforts and attempt to verify those stage/excess air correlations, and test our field experience against the laboratory generated data.⁵

CYCLONES

Cyclone furnaces were designed to burn midwestern bituminous coal, high in iron and sulfur, having medium ash fusion temperatures. The commercial application was successful and a total of 1,100 cyclone furnaces presently exist. The cyclone, in order to work properly, requires coal crushed to the correct size, a slag layer coating the inner surface of the barrel to hold the coal particles, and a slag tapping capability that has demonstrated up to 75 percent slag removal from the flue gas stream. Local clean air regulations have encouraged the shifting of fuel from high-sulfur original design coals to low-sulfur western fuels. The ash fusions associated with the western replacement subbituminous coals are low and do not permit the development of a barrel slag layer.

This lack of slag in the barrel leads to increasing unburnt carbon carryover. We have established a development program to modify the present cyclone design to better handle these off-design subbituminous coals and that program is underway. Additionally, it has become apparent that a fundamental study in NOx reduction should be undertaken. The unstaged cyclone furnace, firing a midwest bituminous coal can and does, when adjusted properly, generate NOx levels in excess of 1200 ppm. Concepts emerging from the various MHD programs indicate "superhot" is an approach that must be explored and could be applied to the cyclone to reduce NOx. The classical two-stage approach is not appropriate with the base design fuels due to the potential for catastrophic corrosion. Various novel concepts advanced in house and by John Pohl of EER and Steve Lanier of U.S. EPA, coupled with the commercial availability of bimetallic corrosion resistant tubing, now offer the potential for the practical application of two-stage fuel rich combustion (Figure 7). The direct firing of coal water slurries in a cyclone furnace (1960), using 65 percent coal/35 percent water, proved successful at that time and as a side effect aided in controlling railroad coal rates by adding an alternative transport mode. Highly loaded slurries (70 percent coal plus) are now a potential fuel source that could, in the cases studied, lower NOx significantly in a cyclone due to the reduced flame temperatures and the reduction in the thermal NOx contribution. The coal-fired cyclone, in a modified form to achieve 90 percent ash removal, could be a clean gas generator for steam generators presently firing natural gas or oil. The cyclone developmental program now underway at B&W includes updated designs for the current cyclone population to better handle actual vs design fuels, the work on the potential clean gas generator for retrofits, and the superhot low NOx generator.

RETROFITS

Ambient air quality degradation and proposed acid rain legislation, where NOx reductions can be credited against SO₂ required reductions, indicate that existing old stationary sources may be candidates for low NOx retrofits. Described already are the concepts planned for application to the cyclone furnaces; what follows is a description of our pulverized coal program.

The Distributed Mixing Burner (DMB) EPA concept developed on the laboratory scale by EER Inc. and applied to a small utility boiler by EER/FW does, under staged conditions, offer an alternative low NOx device for new steam generators. Our project, under EPA funding, was to locate a large utility host site to retrofit the B&W version of the DM burner. The clients who were agreeable to such a demonstration did not possess host sites that met all the site-selection criteria and we were not able to perform the retrofit evaluation. This disappointing outcome resulted in a redirection of the program. It will now consist of the field evaluation of a circular burner and Dual Register Burner, to obtain benchmark data. Those burners will then be characterized in the EPA's Large Water Simulator (LWS), along with the B&W version of the DMB. The three burners fired with the same fuel in the same facility will permit us to project actual NOx levels that would have been attained

on a retrofit unit. The results will provide us with information in sufficient detail to permit us to predict commercial guarantee levels similar to what was necessary when only the EC Gaston Dual Register Retrofit Data was available in 1972.

The Dual Register Burner, when developed, had to be installed as a retrofit because we could not afford to wait the typical 5-year span associated with date of sale/commercial operation, typical of the early 1970s. In the case of that host site, S.E.G.Co. E.C. Gaston Unit #1, the retrofit was feasible. The furnace size, the existing burner throats, and the slagging and fouling characteristics of the fuel were all compatible and the retrofit was successful. Each potential retrofit however must be studied to insure compatibility with a low NO_x system.

Our series of steam generators sold during the highly competitive 1960s were fitted with turbulent diffusion cell burners and furnaces sized to induce rapid intense combustion. These units are coal fueled and represent approximately 30,000 MW of capacity now approaching the 20-year remaining life point. The typical NO_x generated from these pre-NSPS units ranges up to 900 ppm and provides an opportunity for reductions, if required. Our retrofit concept for the cell burner is a locally-staged low NO_x circular burner. The low NO_x circular burner, provided with swirl control and controlled fuel/air mixing with a conical diffuser, has been single-burner field tested with encouraging results. A full-scale retrofit is desired, but would require external financial support (Figure 8).

LABORATORY FACILITIES

Since the last symposium, we have added several major fossil fuel facilities that will permit further investigations into the slagging and fouling characteristics, combustion of new fuels, and lower NO_x concepts. The Laboratory Ashing Furnace (LAF) has been redesigned, rebuilt and returned to service. Micronized fuels have been characterized on this facility and indicate reduced ash deposition rates, but have demonstrated increased compression strengths when compared to the parent pulverized coals. The five-million Btu tunnel has completed the LNCS and micronized firing trials and is currently dedicated to the EPRI/B&W coal water firing trials. Management has authorized the addition of a atomization facility equipped with laser diagnostics to determine particle size, particle distribution and particle velocities. Coal water and limestone atomization studies have been carried out since August 1982, when the facility went into operation. A new five-million Btu furnace, providing wall-firing capability, is under construction and will be operational in February, 1983. A solid fuel handling and pulverizing (MPS mill) system has been added to fuel this furnace and permit additional in-house fuel characterizations. The LNCS and after-burning concepts will be utilized to aid in the start-up/shakedown/characterization efforts in this facility (Figure 9).

OIL/GAS

The high nitrogen liquid fuel burner (HNLFB) has completed 5×10^6 Btu trials and is now being demonstrated on the Stirling Furnace at 40×10^6 Btu/hr input. EPRI donated SRC-II with a 1.0% nitrogen content to aid us in evaluating this flexible low NO_x oil/gas burner. No. 6 oil with 0.2 percent nitrogen was also utilized and both fuels demonstrated low NO_x (70 percent less than a circular burner) for this facility. The flexibility of this burner was demonstrated when it was utilized for coal-water firing trials and was successful in obtaining satisfactory turndown, stability, and carbon utilization. This burner represents a retrofit product that could be applied to pre-NSPS units to reduce NO_x.

Researchers have confirmed the effect of atomizer design upon NO_x generation by revising our standard Y-jet drillings slightly to group exit channels. This minor change reduced NO_x by 25 percent using the same base fuel, burner, and furnace. This effect is being field evaluated now and we expect to see potential reductions.

The HNLFB burner is projected to reduce NO_x emissions by 75 percent from uncontrolled levels. The HNLFB burner coupled to the LNCS/after-burning system is expected to be capable of 90 percent + reductions when compared to uncontrolled sources.

RESEARCH AND DEVELOPMENT

Research and Development plans for the 1980s will be concentrated in four major NO_x areas. The first is that of the fuel nitrogen correlations which govern the NO conversions in both solid and liquid fuels. The second major area is to obtain field demonstrations of the LNCS/after-burn system, cell burner retrofit, and HNLFB burner retrofit. The third area is to continue development work on the cyclone furnace concepts and apply them to commercial-sized retrofits once laboratory results are complete. The fourth area concerns synthetic fuels and our continued work characterizing and burning such fuels as SRC I, II, COM, CWS, Exxon Donner Solvent product fuel, char and other liquefaction products from coals. We have gained extensive experience with some of these fuels under DOE, EPRI and in-house funding; however, the burning, fouling, slagging and handling characteristics of some of these fuels require further work.

SUMMARY

Results from the 34 pulverized-coal units in service to date show that the Dual Register Burner/Compartmented Windbox system is an effective tool for NO_x control. NO_x levels up to 60 percent lower than those achievable with the high-turbulence circular burner system are obtained on approximately 20,000-MW NSPS units. Additional field demonstrations applying the LNCS/after-burn system, cell burner retrofit and cyclone furnace updates are required to meet the increasingly strict NO_x emission limitations expected during the next 6 years. This applies to both new sources and old sources.

The combined effects of industrial recession and conservation have restricted traditional utility growth rates but it is anticipated that by 1985, we will have applied the Low NOx Dual Register System to 125 utility steam generators with an approximate capacity of 60,000 MW. Typically, these units will generate half of the NOx they would have had if the New Source Performance Standards of 1971 had not implemented emission controls.

ACKNOWLEDGMENTS

The author appreciates the assistance of T. Sommer, Combustion Technology; A. LaRue, Combustion Specialist; and J. Fairbanks, NOx Specialist of Fossil Power Systems; G. Lindstrom, G. Farthing, T. Morris and C. Eckert of the Chemical Engineering Section R&D Division; and C. Lane, Manager, Fuel Equipment Design, Industrial and Marine Division for their help in obtaining and reducing the data upon which this report is based.

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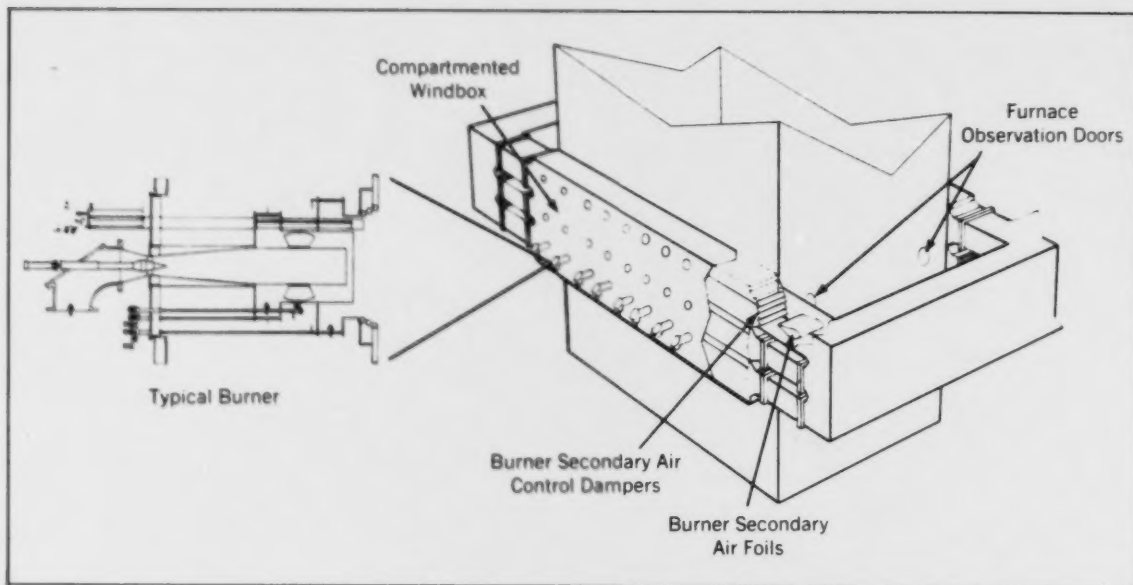


Figure 1 Dual register burner/Compartmented windbox system

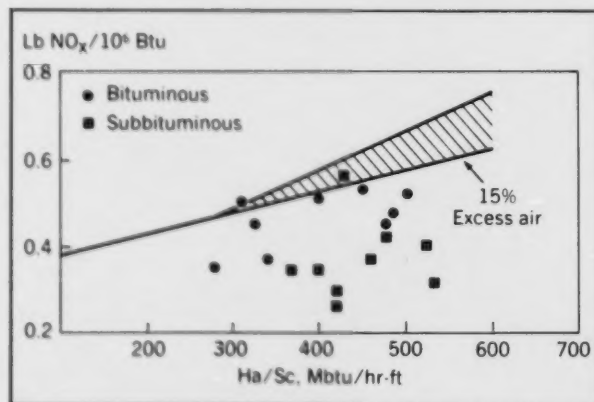


Figure 2 Field test results

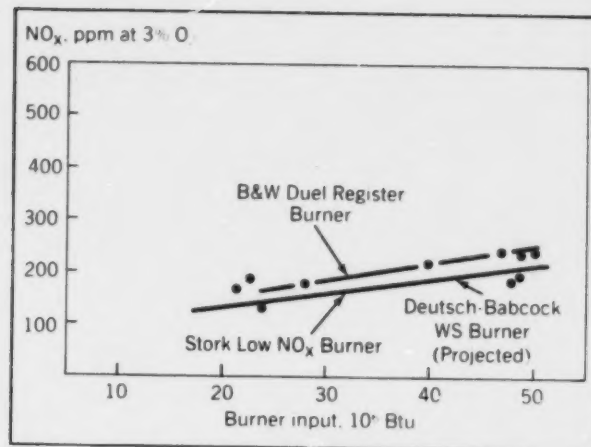


Figure 3 Multifuel low NO_x burners

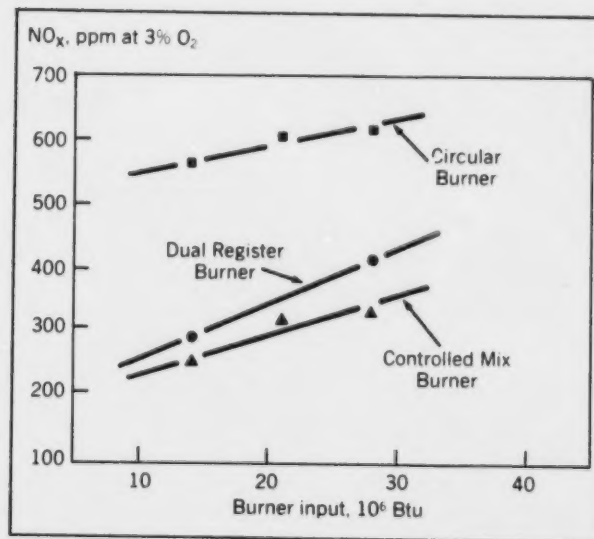


Figure 4 B&W FM boiler (coal firing)

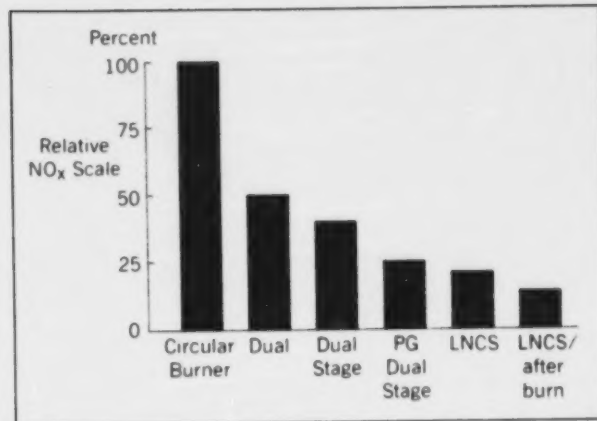


Figure 5 B&W low NO_x (coal) development

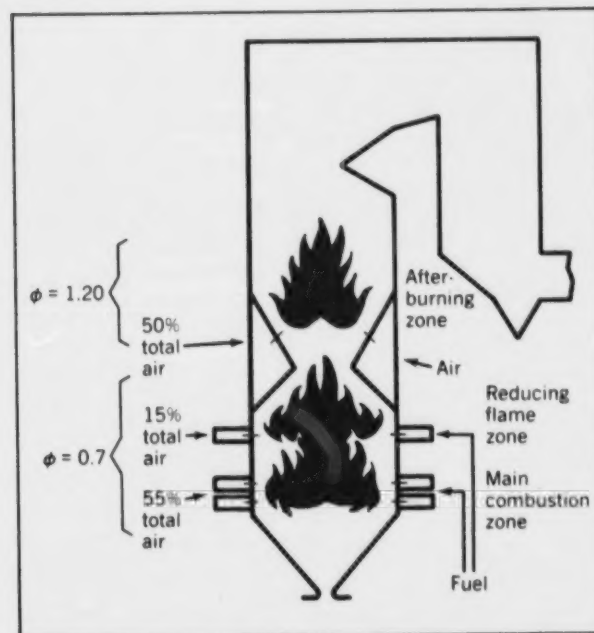


Figure 6 LNCS/after-burn concept

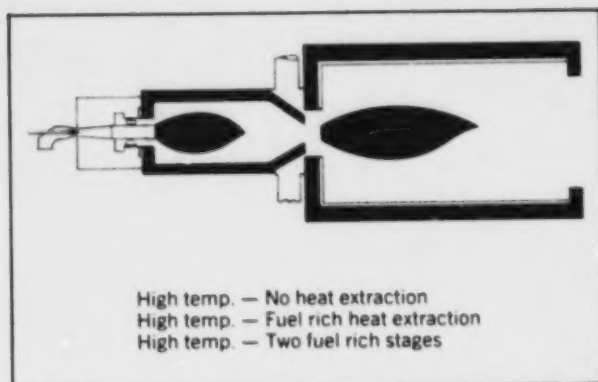


Figure 7 Cyclone concepts to be examined

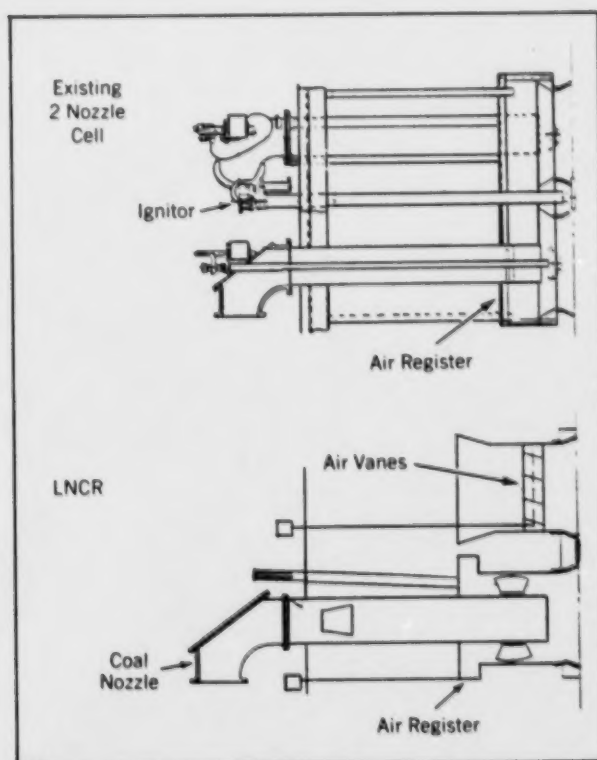


Figure 8 Cell burner retrofit

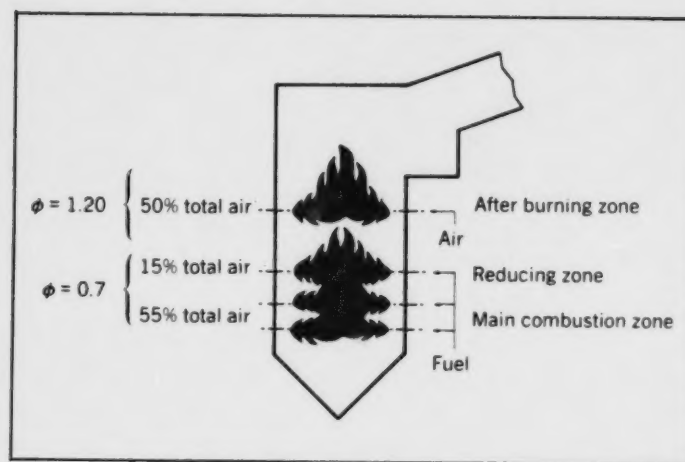


Figure 9 5MMbtu test furnace
(LNCS/after-burn concept)

STATUS OF TANGENTIAL FIRING LOW NO_x TECHNOLOGY

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ABSTRACT

Since 1971, the firing systems that C-E has used to meet NSPS have remained essentially unchanged. Although overfire air (OFA) has been supplied on all C-E units since 1971, it is needed, in most cases, to meet only the 1979 NSPS. Thus, units designed today to meet the current standards have the benefit of eight years of operating experience. To maintain an orderly transition in fuel firing system design, C-E has two major, parallel programs to meet lower NO_x levels on both new and existing boilers in the 1980's.

The first program, which is being developed with the EPA, is the Low NO_x Concentric Firing System (LNCFS). The second is the PM burner developed by Mitsubishi Heavy Industries (MHI) and licensed by C-E for application in the U.S. and Canada.

INTRODUCTION

Since 1971, the firing systems offered by Combustion Engineering, Inc. to the utility market to meet either the 1971 or 1979 New Stationary Sources Performance Standards (NSPS) have remained essentially unchanged. The combination of tangential firing with overfire air (Fig. 1) has produced NO_x levels consistently below the 1979 standards with minimal impact on initial capital cost or long-term operating cost. The 10-year track record of actual operating experience with this package shows that every guaranteed NO_x level has been met without field modifications to the original equipment.

Since the introduction of the NSPS in the early seventies, the regulatory process has changed significantly. In addition to NSPS, various regulatory agencies are requiring much more restrictive NO_x levels on a site specific basis with such strategies as Best Available Control Technology (BACT), Lowest Achievable Emission Rate (LAER), Prevention of Significant Deterioration (PSD), and offsets. Thus, the boiler manufacturers no longer have the luxury of providing a single firing system designed to meet a single national standard. Clearly, different systems are needed that can be offered individually or in combination to meet the requirements of a specific job. C-E is drawing upon

advanced combustion technologies and catalytic reduction technology to produce the most cost effective system for any given level of NO_x . No one system can economically satisfy the range of requirements. (Fig. 2).

To have the flexibility to provide these systems, C-E has basically three programs.

The first program is directed toward "retrofittable" advanced combustion concepts designed for NO_x levels in the 0.3 to 0.4 lb per million Btu range with minimum impact on cost and operating complexity. To satisfy this requirement, C-E is pursuing with the EPA (Ref 1) a concept called the Low NO_x Concentric Firing System (LNCFS) (Ref 2). An important feature of this system is that it can be retrofitted into any existing C-E boiler. The ability to retrofit existing units with this new firing system, without extensive revamping, makes it feasible to test a full scale firing system in the field, determining technical adequacy and commercial viability relatively quickly. When this is done--and the test program is now being conducted--we believe C-E customers will have a low cost option to deal with stricter NO_x requirements, offsets, acid rain legislation, etc.

The second program represents more complex and expensive technology directed toward more restrictive NO_x requirements, 0.2 to 0.3 lb per million Btu. Through a licensee agreement with Mitsubishi Heavy Industries (MHI), C-E has obtained the rights to build the MHI PM firing system (Ref 3). With the PM system, NO_x levels of 0.2 lb per million Btu on most coals are possible. This system can be retrofitted into some boilers, depending on their heights. The ease and costs of installation are proportional to the level of NO_x emissions required.

The third program is the Selective Catalytic Reduction (SCR) process, which is also licensed from MHI. This system is directed toward NO_x levels of 0.1 to 0.2 lb per million Btu. Combining the PM system with an 80 percent efficient SCR, NO_x levels of 0.04 lb per million Btu can be achieved, though it would be very expensive. Since this system is an "add-on" catalytic system and not a firing system, it will not be discussed further in this paper. Details of the system, however, can be found in Reference 4.

THEORY

Control of NO_x in coal-fired units in the early seventies was based on two principles. First: Reduce the turbulence and temperature of fuel and air early in the combustion process. Second: Withhold excess air from the initial bulk combustion process (Figure 3).

Today, the main technique is almost opposite to the first principle stated above. Now we seek to promote early rapid heating of the fuel and turbulent mixing of the fuel with the primary air. But we strive to delay the mixing of the turbulent primary air/fuel mixture with the secondary air until such time that the volatile matter has been released from the pulverized coal particles. The release of that fraction of fuel-bound nitrogen contained in the volatile matter in an oxygen deficient zone is fundamental to the current theory of designing low NO_x emission combustion systems. Although we still try to withhold excess air from the initial bulk combustion process, our efforts are directed primarily at the available oxygen concentration in the region of volatile matter release from the coal.

When fuel systems designers were developing systems for NO_x emission reduction based upon the formation of NO_x by thermal fixation of atmospheric nitrogen and conversion of fuel bound nitrogen, the early practices made sense. Through the efforts of fundamental combustion research in coal molecular structure and nitrogen bearing compounds (NH_3 , CN, NO, etc.) released at various stages of the solid fuel combustion process, the combustion system designer has become increasingly aware of the importance of the fuel bound nitrogen associated with the volatile matter in the solid fuel. Today, we know that if the all-important fuel nitrogen conversion rate is to be controlled, we must make the fuel bound nitrogen compete for available oxygen with intermediate hydrocarbons or any element that has a higher affinity for oxygen than elemental nitrogen. For a burner design, this principle translates into a variety of techniques to keep the primary fuel/air stream as fuel rich within the furnace for as long as possible. The LNCFS and the PM system are two different firing system designs to achieve NO_x emission reduction using this theory.

LOW NO_x CONCENTRIC FIRING SYSTEM

In a standard T-fired windbox arrangement, the primary fuel air streams and secondary air streams are directed toward the tangent of the same imaginary circle in the center of the furnace. Thus, both streams are adjacent and, as with any jet, will entrain one another. The entrainment of secondary air by the primary fuel air jet enriches the fuel with surplus O_2 . In the patented LNCFS method*, the jets are separated; the secondary air jet is directed away from the fuel stream (Fig. 4) and closer to the furnace walls, that is, toward a larger firing circle, which is concentric to the fuel firing circle. Figure 5 shows the LNCFS nozzle. By doing this, the fuel jet entrains only the furnace atmosphere through which it travels, which is significantly lower in O_2 than the fresh air auxiliary jet. Since both the fuel and air streams eventually get mixed thoroughly by the bulk mixing pattern of tangential firing, the separation between fuel and air is for a limited time only.

To maximize the effect of LNCFS, a flame holder has been added to generate fuel and air turbulence at the coal nozzle discharge and to increase fuel residence time in the resulting recirculation zone.

Full scale testing of LNCFS is now in progress at the Utah Power and Light Hunter Station. Figure 6 shows a photograph of the prototype auxiliary air bucket with adjustable vanes presently in service at Hunter station. Preliminary results are presented in Ref (5). The NO_x reduction achieved thus far is significant and there is a high probability that further reductions can be achieved. It is C-E's intent to expand this program through additional research within C-E's Kreisinger Development Laboratory in 1983 and an additional field demonstration in 1984.

* U.S. patent 4,294,178 of Richard W. Borio and Arun K. Mehta for "Tangential Firing Systems," issued October 13, 1981.

PM SYSTEM

In the second program, the PM system, the MHI/PM windbox design goes several steps beyond the LNCFS. First, and perhaps most significantly, the primary fuel/air stream is separated, external to the windbox, into fuel rich "conc" and fuel lean "weak" compartments (Fig. 7). In elevation, the nozzles are arranged such that two "weak" nozzles are combined and separate, by a considerable distance, individual fuel rich "conc" nozzles. Thus, where LNCFS has horizontal separation of primary and auxiliary jets, the PM has vertical separation of the fuel rich "conc" nozzles. The PM design inherently allows the great majority of the fuel to enter the furnace at a very high fuel to air ratio. Gas recirculation is provided in some cases to maintain this fuel rich condition for as long as possible. The vast majority of U.S. coals do not require the use of gas recirculation.

It is interesting to note that OFA has been shown to have roughly the same percent reduction on PM and LNCFS as it does on the conventional tangential systems. Overfire air has been retained as an integral part of both systems.

The PM coal firing system will be demonstrated on an industrial boiler in Japan in 1983 and on two 350-MW units at Sakata Joint Power Company in 1984. Due to MHI's unique and well-proven scale-up technique for low NO_x burners firing gas, oil, and coal, there is little doubt that the PM burner will be able to produce 0.2 lbs of NO_x /million Btu. Test results on the PM burner using a range of U.S. coals are presented in Ref (6).

CONCLUSION

Due to the inevitable trade-off between the increasing cost versus decreasing NO_x levels, a range of advanced combustion systems and the SCR system are being developed to meet the increasingly site-specific NO_x requirement of both new and existing units. C-E's approach involves a combination of both domestic development programs and licensed technology from MHI. Details of the substantial progress in the development of the LNCFS and the PM system are available in References 5 and 6.

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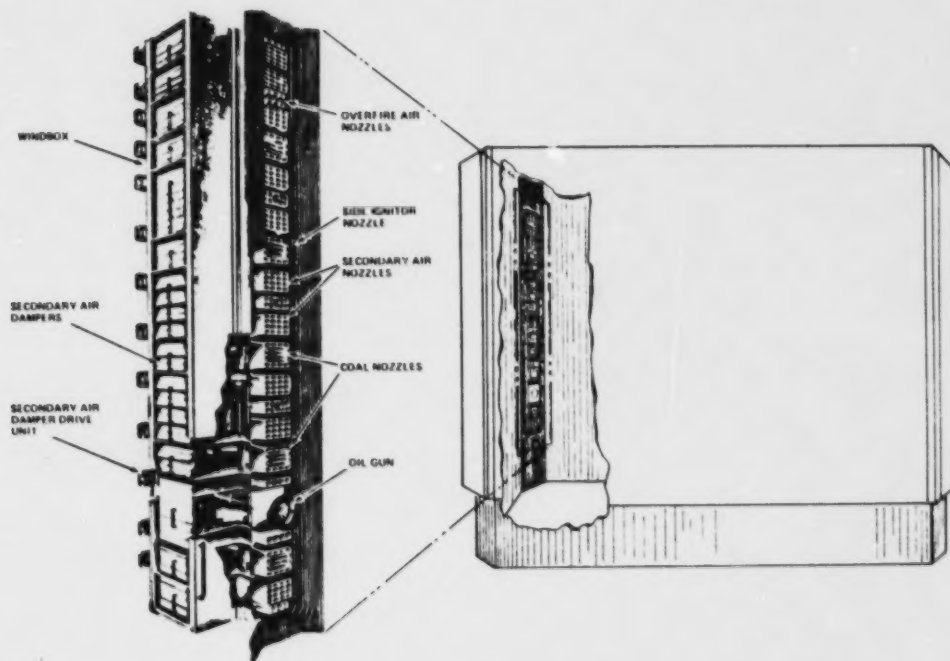


Figure 1. Tangential firing system incorporating overfire air for NO_x control-coal firing.

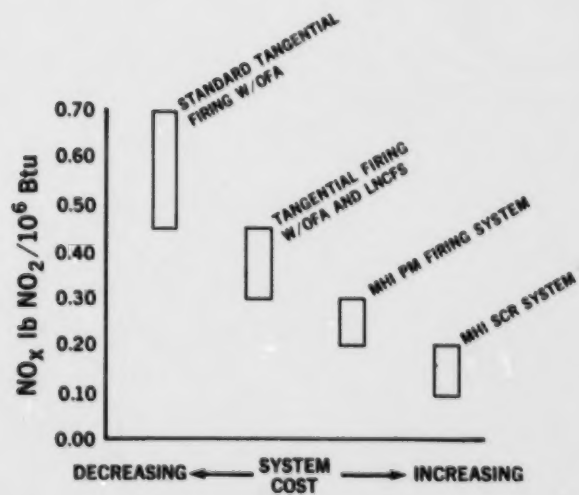


Figure 2. Relative cost trends for various levels of NO_x emissions.

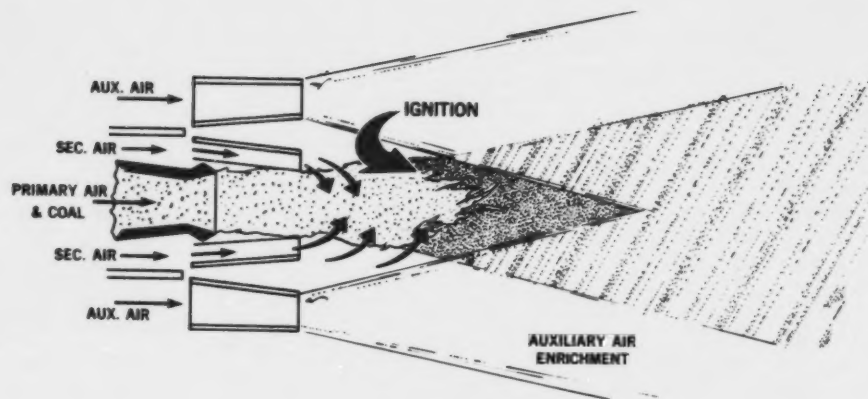


Figure 3. Mixing pattern of conventional tangential firing.

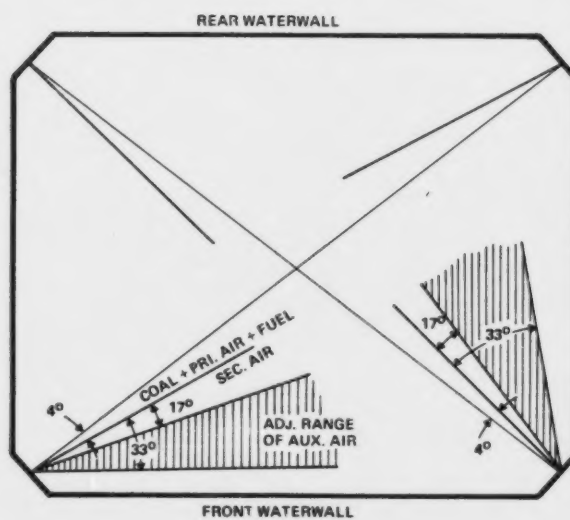


Figure 4. Injection angles for fuel and air--Utah Power & Light Company.

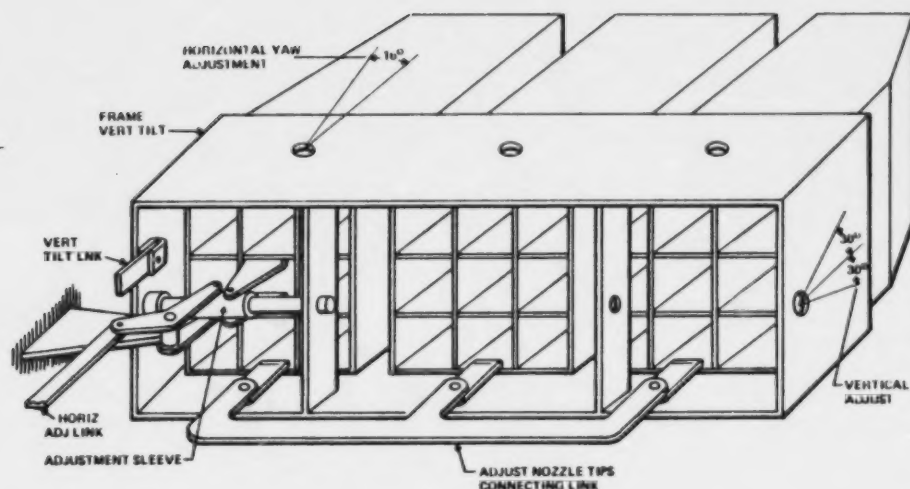


Figure 5. Tilting tangential firing combination of vertical and horizontal, remote adjustment of nozzle tips--Utah Power & Light Company, Hunter 2.

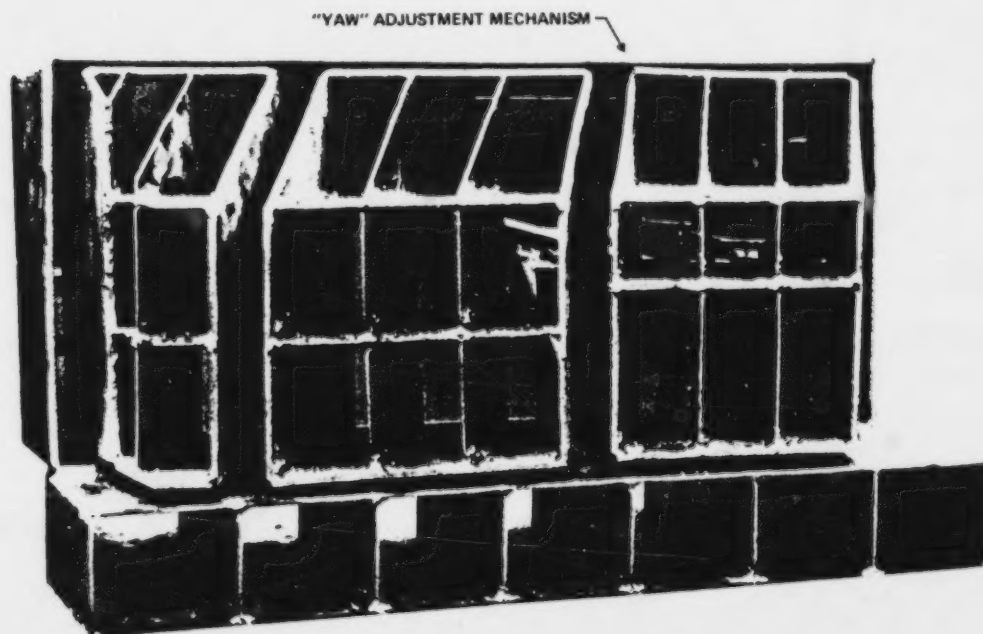


Figure 6. Photograph of prototype auxiliary air bucket with adjustable vanes--Utah Power & Light Company.

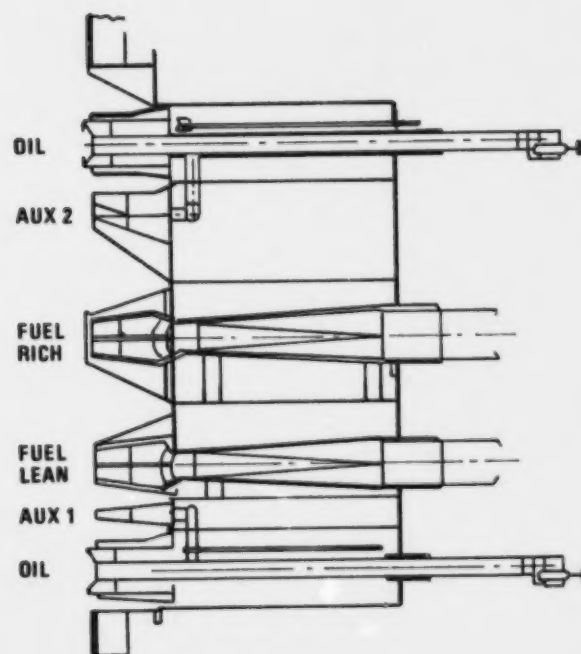


Figure 7. PM cell in tangential firing system

SESSION III

OPERATIONAL AND ENVIRONMENTAL ISSUES
Chairman, David G. Lachapelle
EPA, IERL/RTP

LONG TERM OPTIMUM PERFORMANCE/CORROSION TESTS
OF COMBUSTION MODIFICATIONS FOR UTILITY BOILERS

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ABSTRACT

Extensive field testing is being conducted to evaluate emissions and corrosion at coal-fired utility boilers designed to meet New Source Performance Standards. This work, an extension of similar programs sponsored by the EPA, is intended to evaluate the long term emissions and corrosion effects of combustion modifications instituted primarily for NO_x control.

The work effort of this program is being accomplished in several phases. The first phase consists of preparation and performance of a detailed test matrix designed to provide a thorough characterization of combustion modification (overfire air, low excess air, etc.) techniques applicable to each unit. This results in recommended low NO_x operating conditions for long term testing. Then, during the long term testing, major emphasis is placed on quantitative measurement of furnace tube wall corrosion under low NO_x firing conditions. This is accomplished through evaluation of short term (corrosion probe) test results as well as scheduled long term water wall tube thickness measurements inside the boiler.

Other work performed during the long term test period has included Level 1 environmental assessment testing with physical, chemical, and biological analysis of various effluent streams. Flue gas analysis includes measurement of NO and NO_x, CO, CO₂, O₂ and SO₂/SO₃. Particulate grain loading, size distribution and precipitator capture efficiency are also being evaluated. In addition, several 30-day continuous monitoring tests (NO_x, O₂, CO, CO₂) will be performed at each unit.

The most recent work in this program is also being used in support of EPA's low NO_x burner evaluation for tangentially coal-fired utility boilers.

This paper discusses the results and status of work performed thus far.

INTRODUCTION

Exxon Research and Engineering Company (ER&E), under contract to the U.S. Environmental Protection Agency (EPA Contract No. 68-02-2696), is engaged in extensive field testing to evaluate emissions and corrosion at coal-fired utility boilers. This work, an extension of similar programs sponsored by EPA (1) (2) (3) (4), is intended to provide comprehensive data in an evaluation of the long term emissions and corrosion effects of combustion modifications used primarily for NO_x control.

The work effort of the program is being accomplished in several phases. The first phase consists of preparation and performance of a detailed test matrix designed to provide a thorough characterization of combustion modification (overfire air, low excess air, etc.) techniques applicable to each unit. This results in recommended low NO_x operating conditions for long term testing. Then, during the long term testing, major emphasis is placed on quantitative measurement of furnace tube wall corrosion under low NO_x firing conditions. This is accomplished through evaluation of short term (corrosion probe) test results as well as scheduled long term water wall tube thickness measurements inside the boiler.

Other work being performed during the long-term period has included Level 1 environmental assessment testing with physical, chemical, and biological analysis of various effluent streams. Flue gas analysis includes measurement of NO and NO_x , CO , CO_2 , O_2 and SO_2/SO_3 . (An earlier paper (5) describes the details of the sampling and analysis system.) Particulate grain loading, size distribution, and precipitator capture efficiency are also being evaluated. In addition, several 30-day continuous monitoring tests (NO_x , O_2 , CO , CO_2) will be performed at each unit.

Tests are being conducted at three boilers, each of which is located at a separate host site. The three boilers are the Conesville No. 5 unit of Columbus and Southern Ohio Electric Company (Conesville, Ohio), the Mill Creek No. 3 unit of Louisville Gas and Electric Company (Louisville, Kentucky), and the Hunter No. 2 unit of Utah Power and Light Company (Castle Dale, Utah). The Conesville and Hunter boilers are tangentially fired units, designed by Combustion Engineering (CE), while the Mill Creek boiler is a wall-fired, dual-register burner unit designed by Babcock and Wilcox (B&W). Each of the three units fires pulverized coal, and they all are in the 400-450 megawatt size range. The Conesville and Mill Creek units fire a high sulfur, Eastern coal (~3.5 wt.% sulfur), while the Hunter unit fires a low sulfur, Western coal (~0.7 wt.% sulfur). Note that the Hunter unit is also a part of EPA's low NO_x burner evaluation program for tangentially coal-fired utility boilers.

This paper is organized along the work charter of the contract as described above. Each section discusses a specific group of tasks (e.g., boiler characterization, corrosion testing, etc.) and, where available, pertinent information and results are presented on a per boiler basis.

BOILER CHARACTERIZATION

The characterization tests provided information on the effects of combustion control parameters on NO_x emissions for each boiler tested. The test results are summarized in Table 1, along with pertinent design and operating features. For the purpose of this summary table, low- NO_x emissions are defined as NO_x levels measured for the best combination of combustion modifications (low excess air, overfire air, etc.) that could be utilized at or near the rated capacity of the boiler, without causing significant adverse side effects (e.g., increased slagging, difficulty with steam temperature control, increased tube corrosion, etc.) in short-term tests.

The results from Table 1 indicate that all three of the tested boilers are performing within their applicable New Source Performance Standard (NSPS) for NO_x emissions [$0.7 \text{ lb NO}_x \text{ (as NO}_2\text{) / MBtu} = 301 \text{ ng/J}$]. This is expected since they were designed and guaranteed by their manufacturers to meet these standards. Also, during short-term tests, each of the three boilers was able to significantly reduce NO_x emissions to well below the current NSPS of $0.6 \text{ lb NO}_x \text{ / MBtu}$.

A detailed presentation of all the results obtained in the boiler characterization field tests is beyond the scope of this paper, but will be available through reports to be issued by the EPA. However, for illustrative purposes, discussion of the emission test results, reflecting a particular type of combustion modification for each boiler—overfire air for the Conesville boiler, flue gas recirculation for Mill Creek, and CE's Low NO_x Concentric Firing System (LNCFS) for Hunter*—will be presented in the discussion which follows.

CONESVILLE NO. 5

At the Conesville boiler, excess oxygen levels and overfire air were the two boiler operating parameters which had the greatest influence on NO_x . Figure 1 shows NO_x emissions (at 3% O_2 , dry basis) as a function of excess oxygen levels for various overfire air settings. The uppermost line represents operation without overfire air. As the overfire air dampers were opened from zero to 50% (the second line of this plot), the

*At the Hunter No. 2 boiler, the burners were modified by installation of auxiliary air turning vanes. These vanes created an offset angle between the coal/primary air nozzles and the auxiliary air nozzles. This new system, which is being investigated by CE in the EPA's low NO_x burner evaluation program for tangentially coal-fired boilers (EPA Contract No. 68-02-3655), has been termed the "low NO_x concentric firing system" (LNCFS).

effect on NO_x emissions was very apparent. However, as the dampers were opened further, the improvement in NO_x emissions was not as great, i.e., there is not much difference between the bottom two lines. This reflects the fact that mechanical control (dampers) of air flow is not sophisticated enough from a NO_x viewpoint to discriminate between small changes in damper settings.

In fact, after the overfire air dampers were more than 75% open, further opening only served to bleed the windbox pressure to unacceptably low levels without significantly decreasing NO_x levels. As a result of this testing, the over-fire-air dampers were set on computer control to be 75% open during full load operation.

Some additional items of interest with regard to the work at Conesville include the following:

- As expected, a decrease in excess oxygen levels resulted in decreased NO_x emissions.
- At lower loads, all the NO_x curves shifted downward to lower levels. This confirms previous observations regarding load effects.
- Significant NO_x effects due to burner tilt or overfire air tilt were not found.

The CE design using tangential firing and overfire air proved more than adequate for keeping NO_x emissions within applicable NSPS limits.

MILL CREEK NO. 3

Babcock and Wilcox's (B&W) approach to NO_x control, although different than CE's, also proved to be quite adequate for NSPS NO_x control. B&W uses dual register burners, flue gas recirculation, and reduced oxygen levels for NO_x control; whereas, CE uses tangentially fired burners, overfire air, and reduced oxygen levels.

Figure 2 shows the combined effects of decreased oxygen, and flue gas recirculation on NO_x levels. (Note that NO_x levels are at 3% O₂, dry basis.) Depending on where it is reintroduced in the boiler, the use of flue gas recirculation can be utilized for controlling slag formation, steam temperature, or NO_x emissions. To control NO_x emissions, injection through the windbox is preferred. However, during these tests it was not possible to recirculate the flue gas through the windbox because of equipment maintenance schedules. Instead, the flue gas was introduced through the ash hopper and, as can be seen from Figure 2, still resulted in noticeable NO_x reductions (~10% over baseline conditions).

Other tests performed at Mill Creek indicated that NO_x emissions decreased with decreasing load, and that for full load operation, opening the outer air registers (i.e., diverting some air from the inside to the outside of the flame at each burner) also resulted in decreased NO_x emissions. However, the difficulty in making the register adjustment, and the resulting flame instability at low loads precluded this as a routine method of NO_x control.

Although the Mill Creek boiler is not equipped with overfire air, an attempt was made to create a pseudo-overfire air system by turning off the fuel to one of the upper mills and allowing only air to pass through the affected burners. On other boilers where this has been tried, shutting down single upper burner rows produced an effect much like that of overfire air, with the result being decreased NO_x emissions. However, on the Mill Creek boiler, it was only possible to shut down two rows of burners at a time due to the automatic burner control system. From a NO_x emissions point of view, there would be no advantage to operating the boiler in this way.

HUNTER NO. 2

Over two hundred NO_x characterization tests were performed on the Hunter No. 2 boiler which uses a modified tangential firing system. Parameters investigated include the use of overfire air, LNCFS offset angle, burner nozzle tilts, overfire air nozzle tilts, fuel air damper positions, furnace/windbox differential pressure, and bottom air compartment damper settings.

Results indicate that at full-load firing conditions, the use of overfire air had the greatest effect on reducing NO_x emissions. It was also found that the use of Combustion Engineering's LNCFS had minimal effect on NO_x unless overfire air was also used. This is shown in Figure 3.

In Figure 3, the pre-modification and LNCFS test results at 0% and 100% overfire air are shown. It can be seen that the combined use of LNCFS and overfire air (bottom line of Figure 3) yielded the lowest NO_x levels.* Note that there is only a single line for both the pre-modification and LNCFS test results at 0% overfire air. This is because the differences in their linear regression trend lines were insignificant.

It was also discovered that there is a synergistic effect of burner tilt, offset angle, and bottom air compartment operation on NO_x , but the combined potential NO_x reduction of these effects was small. Like the other two boilers discussed, Hunter No. 2 also had no problem meeting the applicable NSPS for NO_x emissions both before and after the LNCFS modifications.

CORROSION TESTING

Most combustion modifications for decreased NO_x emissions involve decreasing the excess air in at least some local regions of the furnace. This increases the chemically reducing nature of the environment in those

* NO_x levels are at 3% O_2 , dry basis.

regions, and could lead to increase corrosion. Hence, there is concern among boiler manufacturers and operating companies that the combustion conditions needed to comply with NSPS regulations for low-NO_x emissions could lead to increased wastage on the fireside of the boilers' water-wall tubes.

As a key part of this program, fireside corrosion is being evaluated in several ways, including weight loss analysis of corrosion probes (short term testing), and ultrasonic (echo-sounding) measurements of tube wall thickness (longer term testing). The results of this work for the Conesville and Mill Creek boilers are discussed in the subsections which follow. Work at the Hunter boiler is still in progress; therefore, results are not yet available.

SHORT TERM TESTING

Short term corrosion testing was accomplished by use of corrosion "probes." A corrosion probe is an assembly of five coupons of various materials similar to those used in the fabrication of boiler tubes. A simplified drawing of a corrosion probe assembly is shown in Figure 4. During a test, the probe is inserted into the furnace through an inspection door and is air-cooled to the same temperature as the steam-cooled wall tubes (650-700°F). Weight loss analysis of the coupons provides qualitative information on boiler wall corrosion rates.

Figure 5 shows the relationship between average corrosion rate and exposure times for the various corrosion probe tests conducted thus far in the program, including data from the Conesville and Louisville boilers. No difference in corrosion rate was noticed between the various probe materials, nor was there any significant relationship between probe location within the furnace and corrosion rate.

Figure 5 shows that initially, new metal corrodes rapidly, but as it becomes aged and conditioned, its corrosion rate slows and begins to approach the more typical rate for boiler tubes (about 3 mils/yr). This is consistent with results of similar work performed on other boilers.

Some of the coupons from the corrosion probe tests were subjected to metallurgical analysis. No deleterious effects were seen due to exposure in the furnace. The "damage" to the coupons was only surface damage and there was no penetration into the body of the metal.

It should be pointed out that while the short term tests were able to provide qualitative information regarding corrosion rates, the variability in the data was such that it was not possible to make conclusive correlations regarding normal boiler tube life. This emphasized the need for longer term testing.

LONGER TERM TESTING

For longer term corrosion results on actual boiler tubes, the boilers were entered during scheduled outages, and ultrasonic (non-destructive) measurements of the boiler walls were performed. These

measurements were made inside the furnaces on all four walls, at six different elevations (i.e., from the hopper slopes through the burner zones to just below the "nose"). In all, over one thousand individual measurements were made at each boiler.

Cleaning the slag and scale from the outside surface of the boiler tubes prior to sonic determinations of their wall thicknesses is an important aspect of measuring corrosion rates. Since this cleaning process can influence or bias corrosion measurements, the measurement plan was statistically designed to minimize and evaluate any biases due to the tube cleaning procedure.

Table 2 presents a summary of the wall tube measurements made on both the Louisville and the Conesville boilers. The data used to compile this table indicated that all walls corroded at similar rates, and that the corrosion rates inside the burner zones were not significantly greater than the rates outside the burner zones. Both boilers had average wall losses of less than 4 mils (2 mils per year) over the nearly two year exposure period. Also, certain regions of the boiler walls (called corrosion panels) were studied in greater detail. The corrosion rates for the panels were essentially the same as for the rest of the furnace walls.

It is important to note that these results are averages for large groups of wall tubes, and that some individual tubes did have higher (or lower) wastage rates. However, there was no reason to attribute these outliers to low NO_x firing conditions.

The corrosion rates measured at these boilers indicate that on the average it will take more than 25 years for the tube walls to lose half their thickness. This life expectancy is comparable to pre-NSPS boilers.

COMPARISON WITH PREVIOUS CORROSION TESTS

As part of earlier EPA-supported research (Contract No. EPA 68-02-1415), ER&E studied fireside corrosion on furnace walls at Gulf Power Company's Crist No. 7 boiler in Pensacola, Florida. Those studies were the first in which ER&E examined boiler corrosion in detail and included both short-term (probes) and long-term (panels and wall measurements) methods of evaluation. Generally, the experimental methods (probes, panels, and ultrasonic wall thickness measurements) used at Crist were similar to those used at Louisville and Conesville. At the Crist boiler, the studies were performed at both baseline and low- NO_x operating conditions. Results of those studies are presented here so that the reader may compare and observe the consistency of results between the programs.

In the short-term studies (by corrosion probes), the Crist data showed (Figure 6) an initially high corrosion rate which decreased with time to approach the expected (and actually measured) corrosion rate for furnace tube walls. This is consistent with findings at Louisville and Conesville (Figure 5). Furthermore, for the probes, the longer-term rates were generally slightly higher during baseline operation than during low- NO_x .

The longer-term Crist data (by ultrasonic thickness measurement of the furnace tube walls) show (Table 3) an overall wall thickness loss of 2.2 mils (5.2 mils/yr) during the 5 month baseline period: 2.6 mils (6.2 mils/yr) in the non-burner zones compared to 1.7 mils (4.0 mils/yr) in the burner zone. During the subsequent low-NO_x period (12 months), the loss rate was 5 mils/yr in the burner zone and 2.1 mils/yr in the non-burner zones to give a weighted furnace average of 3.4 mils/yr for the 12 month low-NO_x period.

For both the short- and long-term tests, the overall corrosion rates at Crist were consistent with rates measured at Louisville and Conesville.

LEVEL 1 ENVIRONMENTAL ASSESSMENT TESTING

During the longer term testing periods (at the Conesville and the Mill Creek boilers which, as mentioned earlier, commenced shortly after each boiler's characterization work was complete and the boiler was operating in the "Low-NO_x" mode), environmental assessments were conducted based on EPA Level 1 protocol (6). These assessments included physical, chemical, and biological analysis of selected effluent streams according to EPA procedures and techniques.

At each test site, the major process streams related to the operation of the boiler were sampled. This included electrostatic precipitator testing for particulate removal efficiency, and flue gas evaluation for particulate size distribution; volatile organics, and trace metals (using EPA's Source Assessment Sampling System - SASS). SASS testing was conducted upstream of the electrostatic precipitator in order to maximize sample availability. Level 1 work also included coal, sluice water and ESP hopper ash sampling. Results of the Level 1 testing are discussed in the following subsections.

ELECTROSTATIC PRECIPITATOR TESTING

During the Level 1 tests at each boiler, dust loading in the flue gas was measured simultaneously at the precipitator inlet and outlet using EPA Test Methods 5 and 17. Table 4 summarizes the results. The results show that these "cold-side" electrostatic precipitators remove greater than 98% of the dust from the flue gas. (A scrubber located farther downstream removes still more dust from the flue gas.)

PARTICULATE SIZE DISTRIBUTION

Data on the flue gas particulate size distribution comes from a single point SASS run made at each boiler. As mentioned earlier, testing was done at the precipitator inlet to maximize sample availability for subsequent laboratory analysis. Table 5 shows the results of this testing for the Conesville and Mill Creek boilers. As seen in the table, most (~70%) of the particles entering the electrostatic precipitator (ESP) have an equivalent aerodynamic diameter of greater than ten microns. This is consistent between both units, and it also compares well with previous work on other boilers. (3,5,7)

LEVEL 1 - ORGANICS

The objective of Level 1 analyses is to identify major classes of organic compounds present in a stream and to estimate their concentrations. Organic samples were obtained from several streams, including the sluice water (containing the ash flushed from the furnace hopper), the coal feed, the electrostatic precipitator catch, and the particulate-laden inlet (flue) gas to the electrostatic precipitator. The particulate-laden gas stream was sampled using the EPA's Source Assessment Sampling System (SASS). This system collects particulates by physical means, while volatile organics are captured by condensation and adsorption methods. The other stream samples were obtained by simply obtaining "grab" samples. Analyses of the samples were obtained using EPA procedures which specify an extractive approach where a solvent is used to extract the organics from the bulk samples, and then the extract is subjected to a series of separation and quantification procedures.

Table 6 shows the amount of organics that were extracted from the coal, the electrostatic precipitator catch, and from the flue gas at both the Conesville and the Mill Creek tests. The flue gas organics were sampled and separated into stages using the SASS train. In accordance with EPA Level 1 protocol, those samples having extractable organic portions greater than 10-15 milligrams were subjected to further analysis.

According to protocol, the next stage of identification of the organics is a liquid chromatographic, silica gel separation. This is shown in Table 7 for an XAD-2 sorbent resin sample obtained from testing at the Conesville unit. From the table, it can be seen that of the seven fractions obtained in the separation procedure, fraction No. 6 had the greatest quantity of organics. Again, according to the protocols, that fraction is subjected to further analysis. In general, low levels of organics were found, and those were mostly alkyl esters. Further evaluation of these data are continuing as part of this program and will be reported in the subsequent reports.

LEVEL 1 - TRACE METALS

Another aspect of the Level 1 work is the analysis for inorganics, which is concerned primarily with trace elements, especially metals. Table 8 summarizes the analytical results of a typical SASS train

sample from Conesville and Mill Creek. Thirty (30) different metals were targeted for investigation using inductively coupled plasma emission spectrography. These included the 13 priority metals that EPA has classified for waste waters. Most abundant were found to be silicon, aluminum, potassium, iron, calcium and titanium. The levels were as expected, based on the mineral contents of the coals. Also, of all the metals (including volatiles and non-volatiles) found in the flue gas stream, the largest amount (by total mass) was found on the particles that were entrained in that stream. On a total mass basis, most of these metals were found on the larger (10 and 3 μm) size particles. However, on a concentration basis, the weight of metals per weight of particles was higher for the smaller (1 μm) particles. This suggests that, in general, metals in the flue gas tend to concentrate on the fewer smaller particles. (The exception is mercury, which was found mostly in the condensate and impinger catches of the SASS train. Other volatile metals behaved similarly.) This metal partitioning by particle size is consistent with previous observations. Also, as expected, toxic metals were found at or below their detection limits.

For some of the metals detected, the stack emission rate was compared to EPA's minimum acute toxicity effluent (MATE) values. Of the few components found to exceed their MATE values, most are integral components of the stainless steel parts of the sampling system and it is likely that they came from the sampling system itself, and not from the stack.

LEVEL 1 - BIOLOGICAL ASSAYS

In addition to the physical and chemical characteristics of the process streams, biological effects were also studied. The effects of three samples (coal feed, sluice water, and precipitator catch) on seven biological systems were observed. The results are summarized in Figure 7. It should be noted that responses were similar for both boilers.

Because most carcinogens also act as mutagens, the Ames test (on salmonella bacteria) for mutagenic effects was used to screen samples for carcinogenic materials. Results (first group of three bars in Figure 7) indicate that the coal, electrostatic precipitator (ESP) ash and sluice water are not mutagenic. However, a coal feed sample produced a toxic response.

Similarly, because the lungs are the first defense against toxins on inhalable particles, the rat alveolar (lung) macrophage (RAM) test was used to evaluate this effect. In this test, cultures of rat lung cells were tested for a toxic response to the samples collected. The RAM assay was negative.

The Chinese Hamster Ovary (CHO) Cell Assay is a test for clonal toxicity in which the ability of a clonal cell colony to live and grow, is measured, after being exposed to the material under study. The CHO test yielded toxic responses with coal leachates and with sluice water.

Whole animal toxicity studies (on live rats) were used to evaluate short-term toxic effects. In these "Oral Rodent" studies, the death rate of the animals after ingesting the prepared samples was less than the toxic response to common table salt.

In the fresh-water aquatic tests involving fish (minnow), daphnia, and algae, respectively, only the coal and ash leachates showed toxic responses. The sluice water was not toxic to these aquatic species but promoted the growth of algae.

The moderate to high toxicity of the ESP ash leachate on the test species of minnow and daphnia may have been partially due to the increased hardness of the water as the leachate was added. At low concentrations, this leachate stimulated the growth of algae. However, at slightly higher concentrations, toxic effects were seen, thus placing this leachate in the high toxicity category. For the Louisville boiler, pH increased with increasing concentration of ESP ash leachate and was probably a contributing factor to the observed toxicity.

For the Conesville boiler, the coal leachate showed the greatest toxicity of the three samples tested (ESP ash leachate, coal leachate, and sluice water). In both the fish test and the daphnia test, the pH fell as the leachate was added. And, as with the ESP ash leachate, the specific conductance (a measure of water hardness) increased as the concentration of the leachate was increased. The daphnia test on this leachate showed high toxicity and was probably influenced by both of these parameters. For the Louisville boiler, the coal leachate was not toxic to either the fish or daphnia, but it did have a significant effect on algae.

A more detailed discussion of the biological work performed under this contract is beyond the scope of this symposium paper. However, additional data may be found in the full reports.

30-DAY CONTINUOUS MONITORING TESTS

The other major task being performed as part of this contract is a series of 30-day monitoring tests. In these tests, NO_x , CO , CO_2 and O_2 are continuously monitored for several thirty-day periods, with NO_x emission rates of key concern. Also, the instruments themselves are monitored during these tests to assure that their performances are in accord with EPA specifications for continuous analyzers. Thus far, four 30-day tests have been conducted--two at Conesville and two at Mill Creek--in accord with official EPA protocols and reference methods. KVB, Inc. is performing this work under subcontract to ER&E.

Table 9 summarizes the results of the tests completed thus far. The data were measured continuously over thirty- to forty- day periods during normal boiler operating conditions, i.e., varying boiler loads. These results show that the boilers' NO_x emissions are well within the applicable NSPS limits.

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One point with regard to Table 9 is that during the tests at Conesville, there was a difference between the two 30-day average NO_x levels. This can be attributed to the higher average load during the first 30-day test (300 MW vs. 225 MW).

WORK REMAINING

The preceding sections of this paper summarize the work that has been accomplished thus far in the program. However, additional work remains to be completed over the next two years. This section briefly discusses this remaining work, which includes primarily boiler characterization and corrosion testing at Utah Power and Light Company's Hunter No. 2 unit.

In the boiler characterization area, plans are to perform another series of characterization tests at the Hunter No. 2 unit. This work is intended to provide additional confirmation of the performance of the LNCFS installed at the unit. A test matrix is being developed to evaluate excess air, overfire air, burner tilts, and other combustion modifications and boiler control parameters.

Additional corrosion testing is also scheduled at the Hunter unit. Plans are to conduct a set of 30 hour, 300 hour and 1000 hour short term corrosion probe tests. This work will start in late 1982 and extend into early 1983. For the longer term corrosion testing, the final series of waterwall measurements will occur in the late fall/early winter of 1983, based on an anticipated two-year exposure period. Other work planned at Hunter includes a series of thirty (30) day continuous monitoring tests (NO_x, CO, CO₂, O₂). Five such tests are scheduled.

ACKNOWLEDGEMENTS

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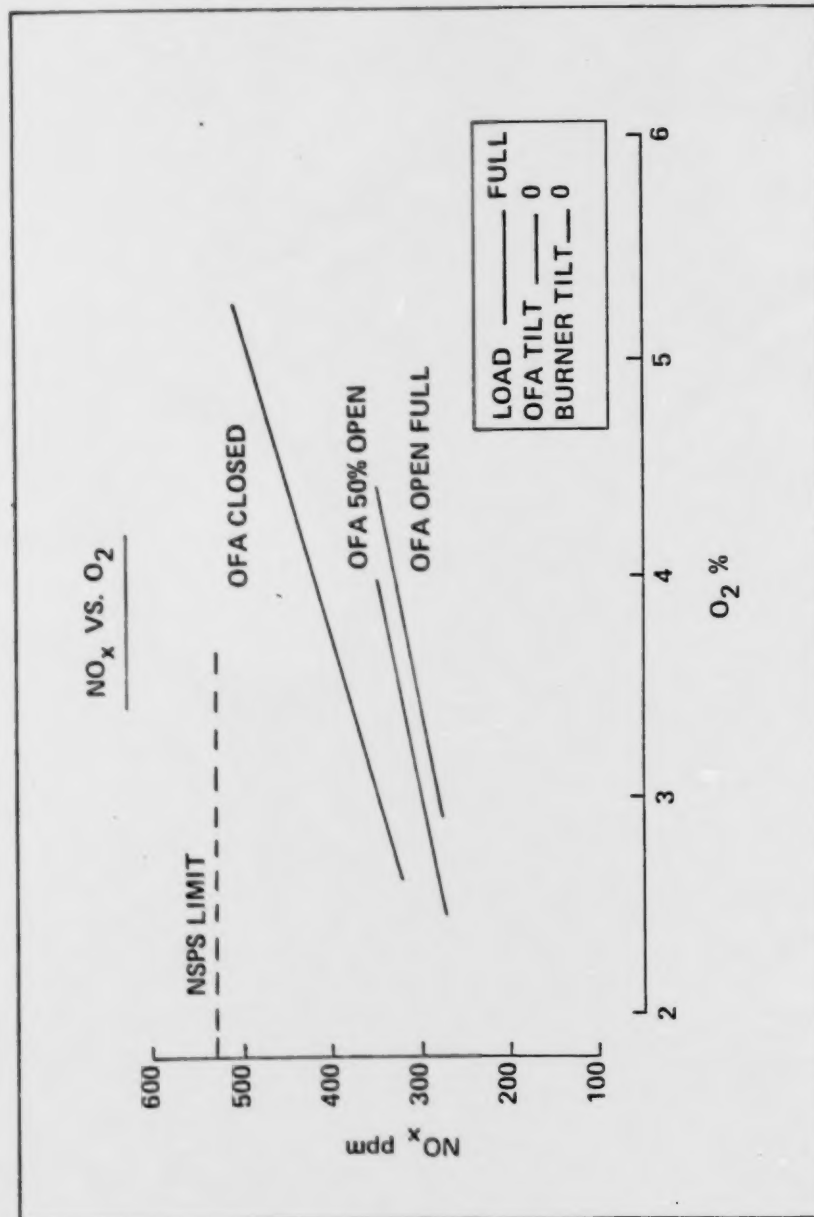


FIGURE 1. COLUMBUS AND SOUTHERN OHIO ELECTRIC COMPANY
CONESVILLE NO. 5 BOILER

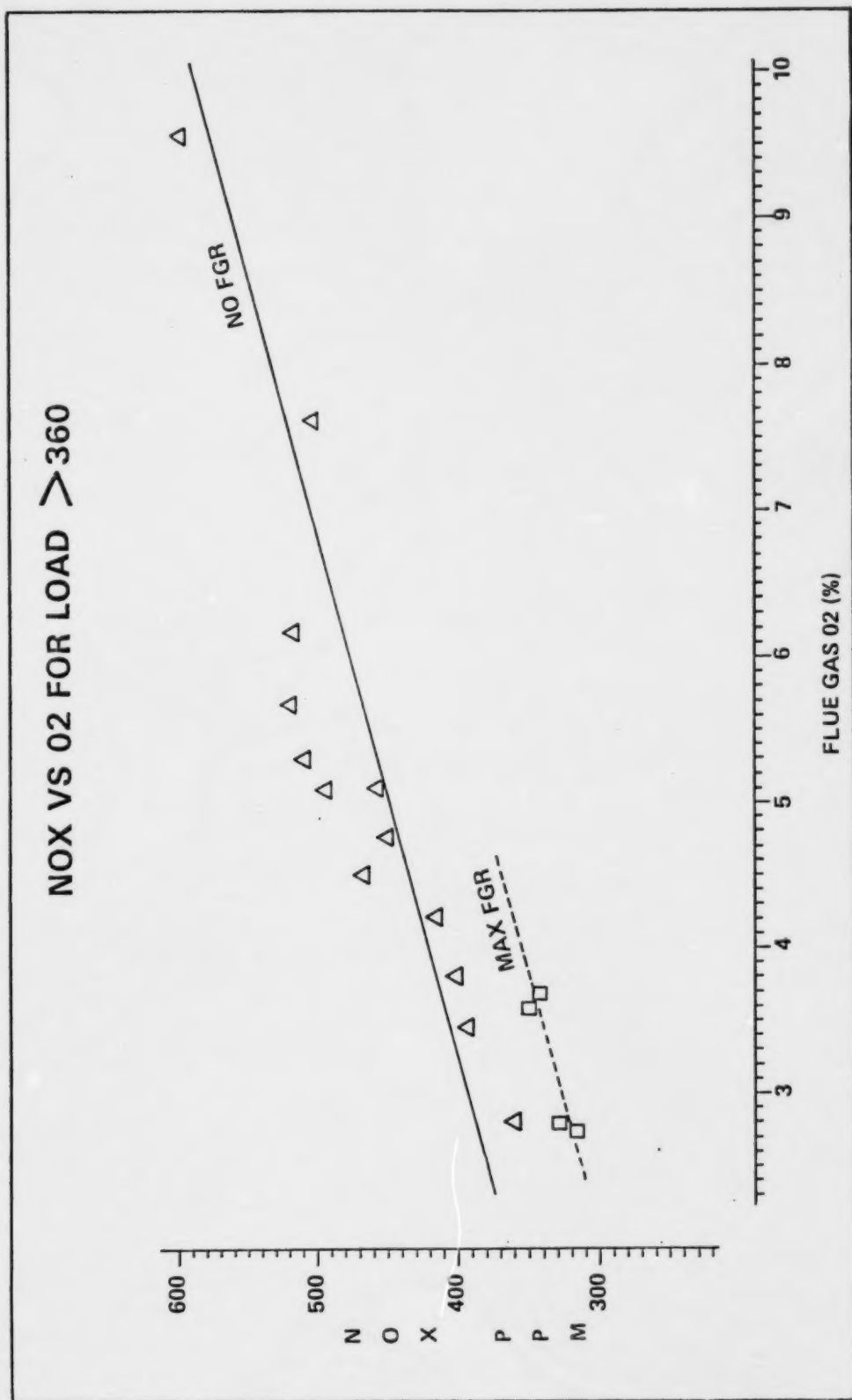


FIGURE 2. LOUISVILLE GAS AND ELECTRIC COMPANY
MILL CREEK STATION, BOILER NO. 3

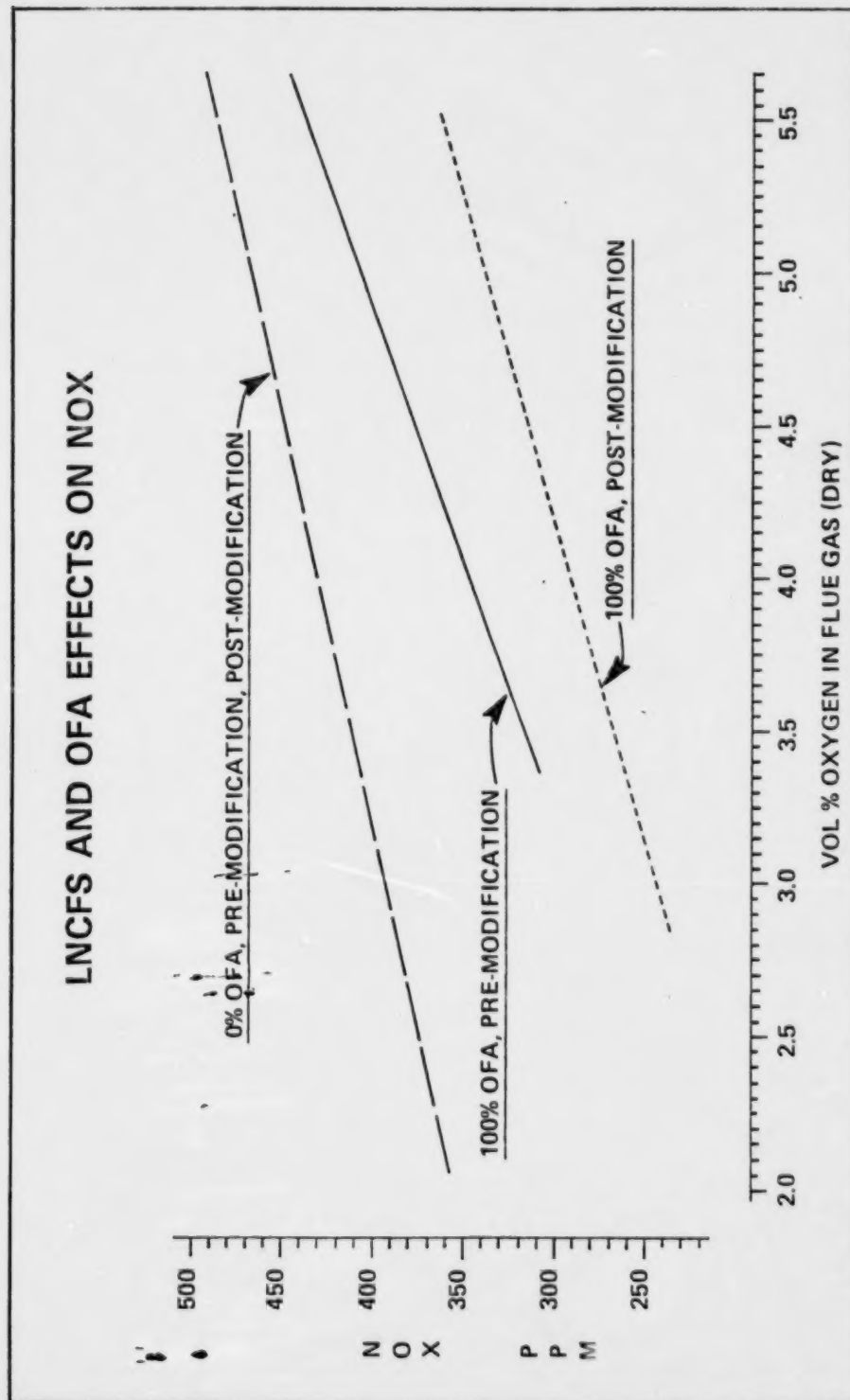


FIGURE 3. UTAH POWER AND LIGHT COMPANY
HUNTER GENERATING STATION BOILER NO.2

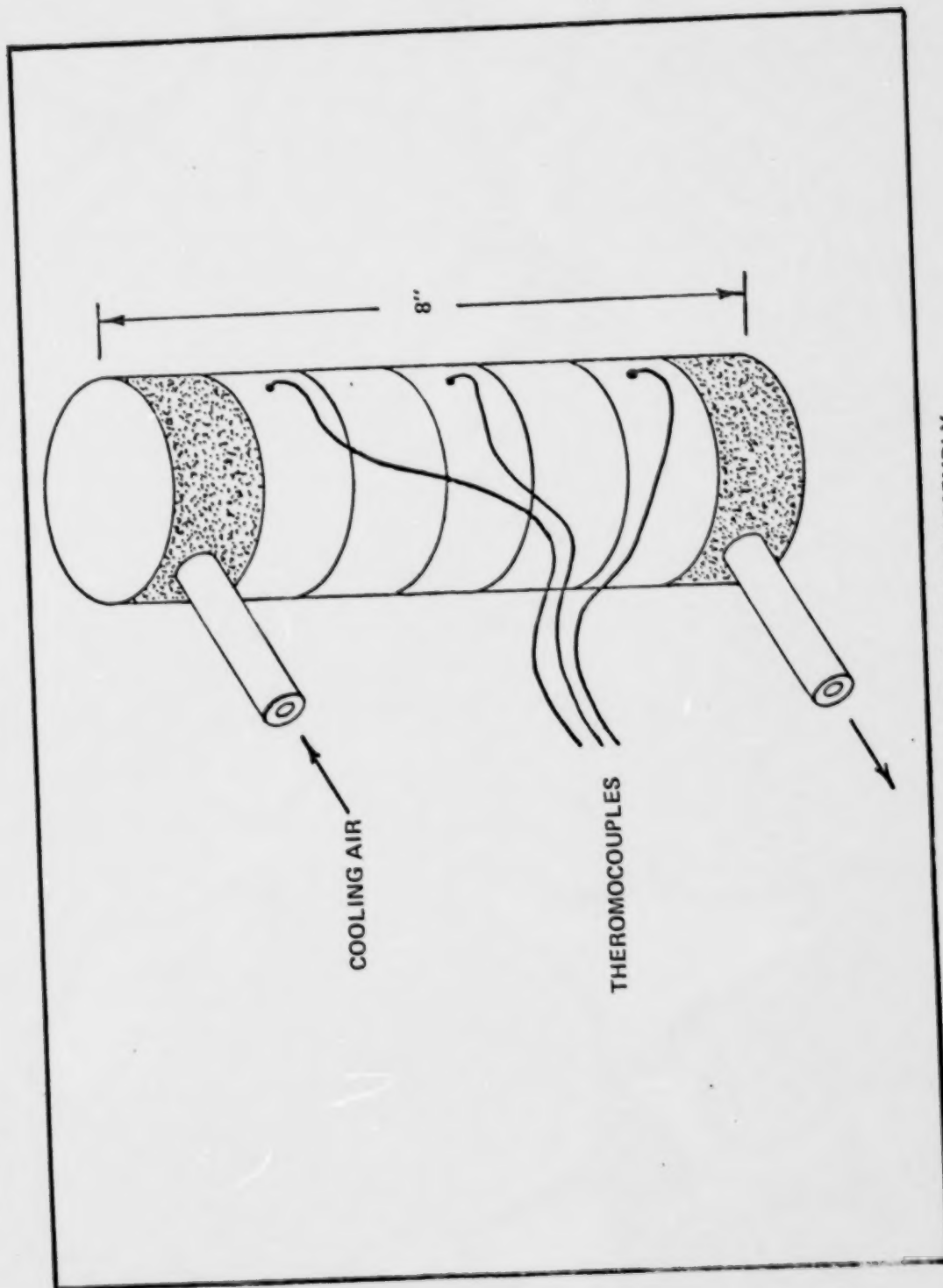


FIGURE 4. CORROSION PROBE ASSEMBLY

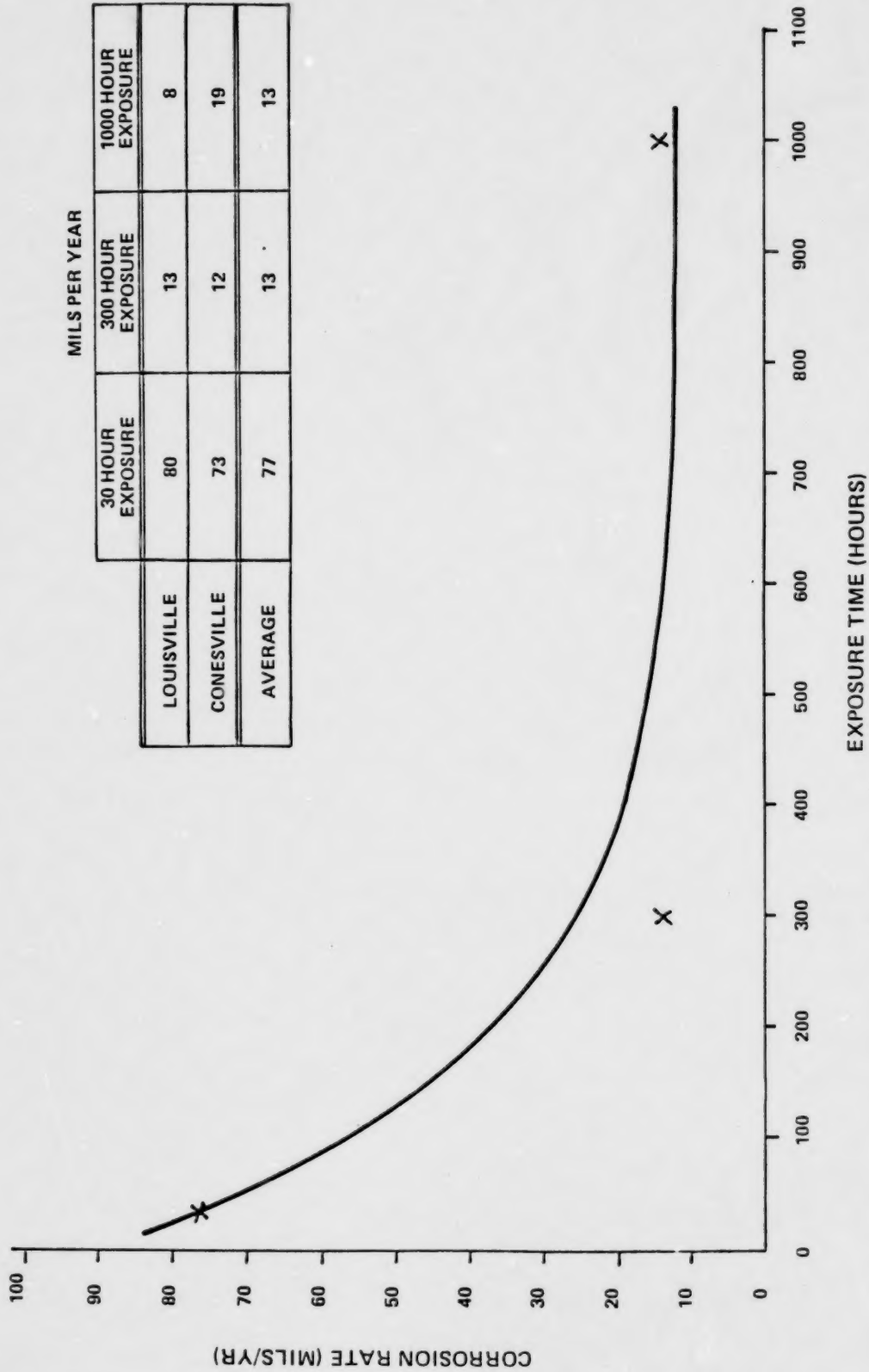


FIGURE 5. SHORT TERM CORROSION TESTING

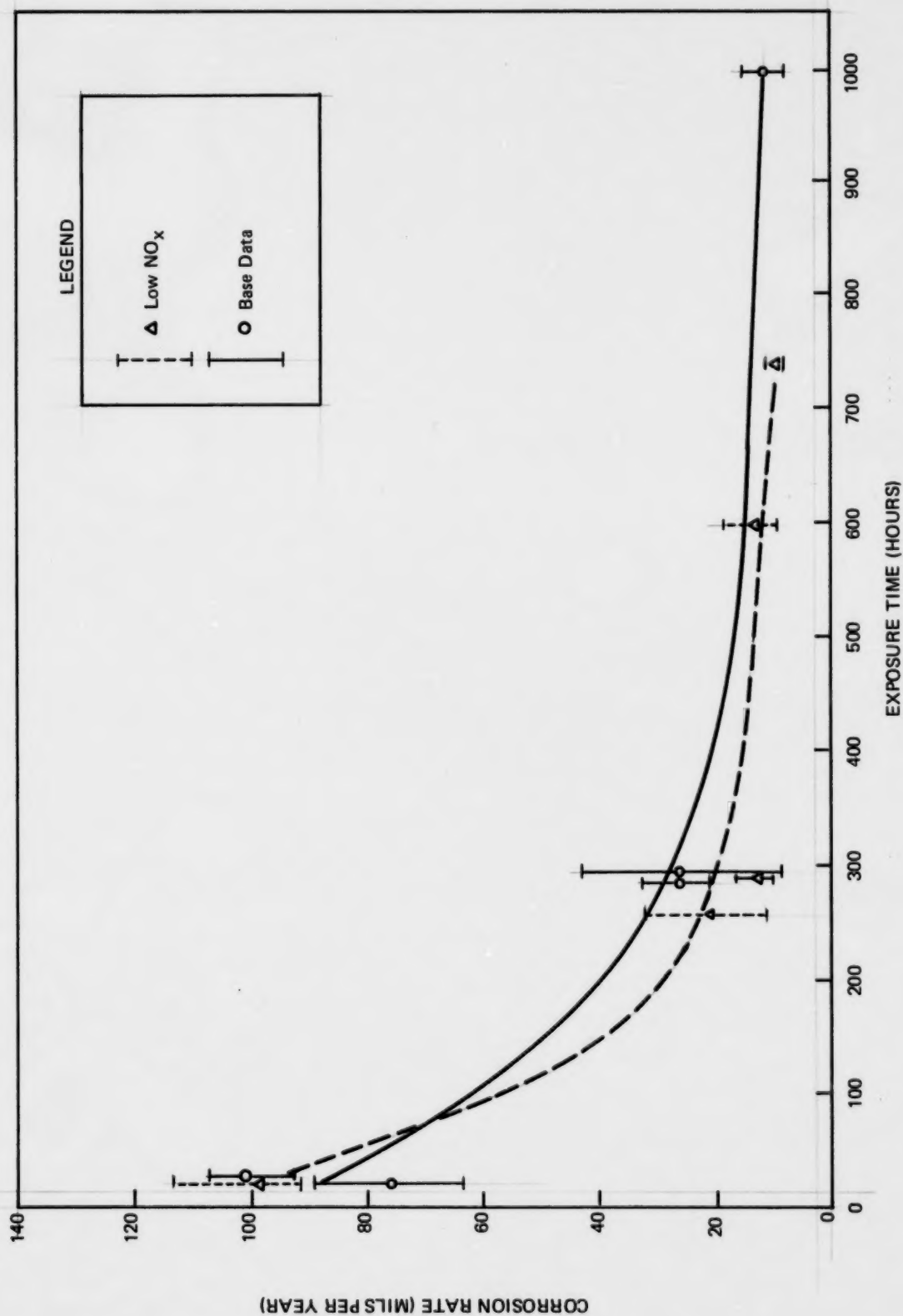
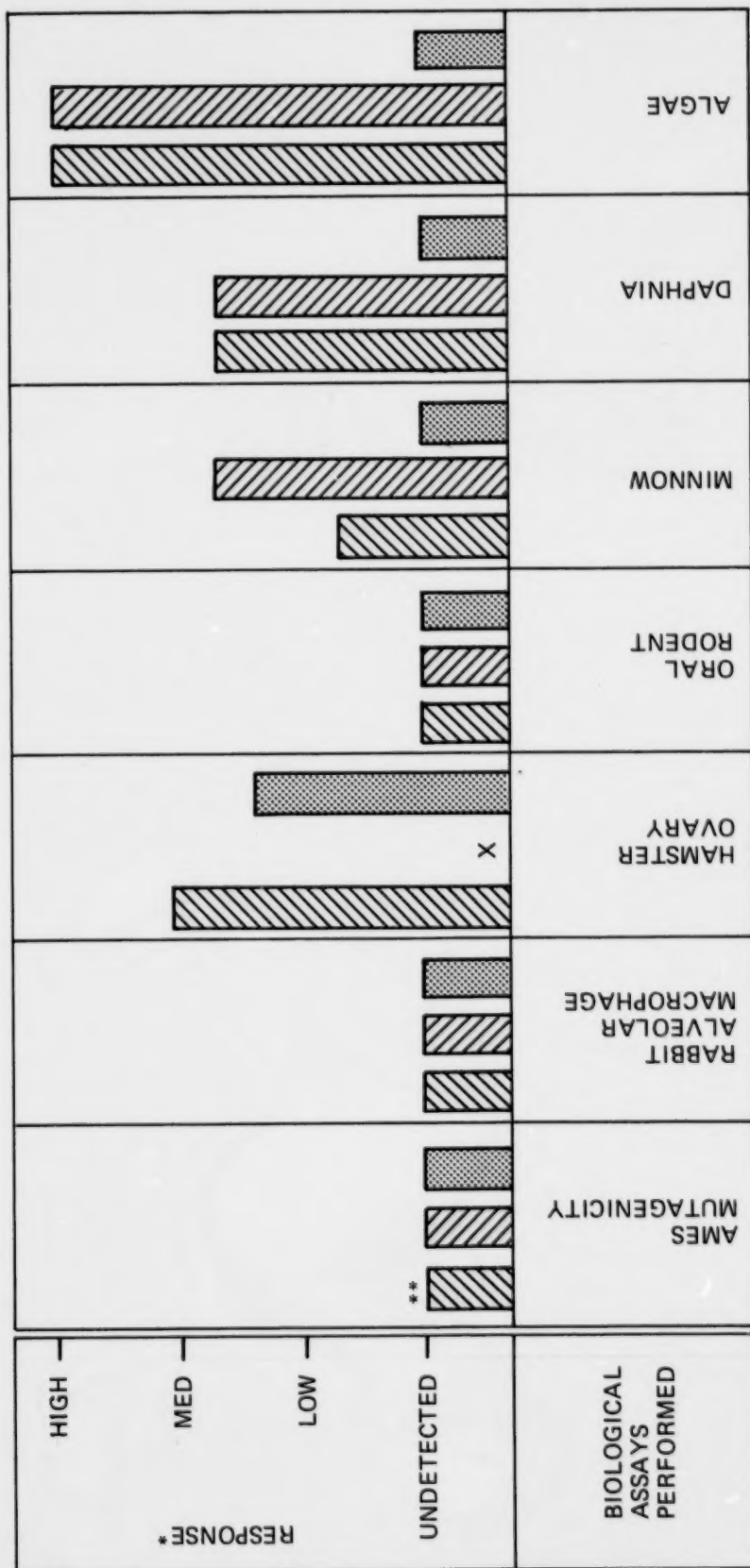


Figure 6
Comparison Of Crist No. 7 Corrosion Rates (Using Probes) For "Baseline" And "Low-NO_x" Operation



COAL FEED

ELECTROSTATIC PRECIPITATOR CATCH

SLUICE WATER

* EXPLANATION OF HIGH, MEDIUM, LOW, ETC. MAY BE FOUND IN THE FULL REPORTS.

** TOXIC EFFECTS INTERFERED WITH THE ANALYSIS FOR MUTAGENIC EFFECTS.

X NOT TESTED

FIGURE 7. BIOLOGICAL ASSAYS

TABLE 1. SUMMARY OF BOILERS PARTICIPATING
IN THE TEST PROGRAM(1)

Boiler Operator	Station and Boiler No.	Boiler Mfr. (2)	Type of Firing (3)	Maximum Continuous Rating (MWe)	No. of Burners	No. of NO _x Characterization Test Runs	Full load NO _x EMISSIONS (8)		
							Baseline NO _x vppm(lb/10 ⁶ Btu)	Low NO _x vppm(lb/10 ⁶ Btu)	% NO _x Reduction
Columbus and Southern Ohio Electric Co.	Conesville No. 5	CE	T	450	20	72	445(0.61)	260 (0.36)	40%
Louisville Gas and Electric Co.	Mill Creek No. 3	BW	HO	435	40	49	393(0.54)	356 (0.49)	10%
Utah Power and Light Co.	Hunter(4) No. 2	CE	T	425	20	212(5)	475(0.65)(6)	350 (0.48)(6)	25%(6)
							450(0.60)(7)	280 (0.38)(7)	40%(7)

(1) All units are coal fired utility boilers.

(2) CE - Combustion Engineering, Inc.

BW - Babcock and Wilcox Company

(3) T - Tangential

HO - Horizontally Opposed

(4) This unit is also part of EPA's low-NO_x burner evaluation for tangentially coal-fired boilers.

(5) Includes pre and post-windbox modification tests.

(6) Includes only pre-windbox modification data.

(7) Includes only post-windbox modification data.

(8) Vppm data is corrected to 3% oxygen dilution, dry basis.

TABLE 2. LONG TERM CORROSION TESTING		
Elevation/Location	Wall Loss (Mils)*	
	Louisville (On-Line Time = 15,000 Hours)	Conesville (On-Line Time = 12,000 Hours)
Nose F	4.0	0.8
E	3.4	2.0
Burner Zone {	D 4.4	2.1
	C 3.7	1.8
	B 3.5	2.9
Hopper A	4.8	1.5
AVERAGE	3.9	1.9
*One mil = 0.001 inch = 0.00254 cm.		

TABLE 3. CRIST NO. 7 WALL MEASUREMENT SUMMARY			
Metal loss in mils (or mils per year)			
	Non-Burner Zone All Walls	Burner Zone All Walls	Furnace Average
Baseline (5 months)	2.6 mils (6.2 mils/yr)	1.7 mils (4.0 mils/yr)	2.2 mils (5.2 mils/yr)
Low-NO _x (12 months)	2.1 mils (2.1 mils/yr)	5 mils (5 mils/yr)	3.4 mils (3.4 mils/yr)

TABLE 4. ESP EFFICIENCY TESTS		
	CSOE - Conesville No. 5	LCE - Mill Creek No. 3
Grain Loading at ESP inlet (lb/MBtu)	7.5	8.6
Grain Loading at ESP Outlet (lb/MBtu)	0.13	0.07
Collection Efficiency, Avg.	98.3	99.2

TABLE 5. SASS - PARTICLE SIZING		
Particle Size, Micrometers	CSOE - Conesville No. 5	LCE - Mill Creek No. 3
	(% of Material Collected)	
>10	76.9	69.8
3-10	20.5	26.2
1-3	2.3	3.5
<1	0.3	0.6

TABLE 6. LEVEL 1 - ORGANICS		
Sample	CSOE - Conesville No. 5 Mg/SASS Test	LGE - Mill Creek No. 3 Mg/SASS Test
10μ + 3μ Cyclone	4.8	4.1
1μ Cyclone	<3.5	<0.5
XAD-2 Resin	50.4	125.1
Condensate	<0.2	<0.2
Coal	37,702	67,725
Fly Ash	5.0	35.1

TABLE 7. LEVEL 1 - ORGANICS (CONT'D.)	
<u>Silica Gel Separation (Conesville)</u>	
Fraction	XAD-2 (Mg/SASS Test)
1	5.8
2	0.8
3	1.4
4	1.7
5	1.7
6	34.5
7	<u>8.1</u>
	TOTAL 54.0
• Low levels of organics detected (mostly alkyl esters)	

TABLE 8. LEVEL 1 - TRACE METALS

- Looked for 30 different metals
- Most abundant metals: Si, Al, K, Fe, Ca, Ti
- Metals in flue gas concentrate on fine particles
- Toxic metals were near or below detection limits

TABLE 9. 30-DAY MONITORING TESTS

TABLE 9. 30-DAY MONITORING TESTS				
Test	CSOE - Conesville No. 5		LGE - Mill Creek No. 3	
	(NO _x Emission Rate, lb/MBtu)			
	1	2	1	2
	Max	0.61	0.52	0.58
Min	0.41	0.32	0.36	0.43
Average	0.53	0.42	0.48	0.51

ANALYSIS OF LONG-TERM NO EMISSION DATA
FROM PULVERIZED-COAL-FIRED UTILITY BOILERS

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ASBSTRACT

Long-term NO emission monitoring data obtained from nine pulverized-coal-fired utility boilers were analyzed. These data were in the form of hourly averaged NO, O₂ (or CO₂), and load with NO and O₂/CO₂ being measured by certified continuous emission analyzers. The analyses were compared to the emissions limitations enumerated in both the 1971 and 1978 New Source Performance Standards (NSPS).

The comparison with the 1978 NSPS showed that seven of the nine boilers would have produced no periods of excess NO emissions on a 30-day rolling average basis. In addition, the same seven boilers would have complied with the 1978 NSPS NO_x performance test requirements.

Recommendations are made to more fully analyze the operation of two of these boilers to establish if their mode of operation could be adopted by other boilers. These boilers use permanently installed CO monitors to allow operation at the lowest practical excess air to achieve either low NO emissions or better fuel efficiency. (This work was funded by the EPA under Contract 68-02-3175, Task 7.)

INTRODUCTION AND SUMMARY

Long term NO emission data obtained from nine pulverized-coal-fired utility boilers were analyzed to determine the degree to which compliance was achieved with both the 1971 and 1978 New Source Performance standards (NSPS). These standards are summarized in Table 1. Pertinent boiler characteristics are summarized in Table 2.

The NO and O₂ (or CO₂) data were measured by certified analyzers. The utilities also supplied hourly averaged unit load, monitor certification reports, and periodic coal analyses as part of the data packages.

A KVB computer program was specially modified for this study to perform the following computations:

1. Daily means and standard deviations of NO, O₂ (or CO₂), and load.
2. Means and standard deviations of NO and O₂/CO₂ as functions of unit load.
3. Load probability.
4. NO probability.
5. Number of periods of excess NO emissions with respect to the 1971 NSPS on both a 3-hour rolling average and 3-hour block average basis.
6. Number of periods of excess NO emissions with respect to the 1978 NSPS on a 30-day rolling average basis.

Site visits were made (as noted in Table 2) to discuss details of monitor and boiler operation. As a result of these visits, revised computer analyses were performed for certain boilers when it was determined that some of the monitor data was of questionable validity.

The results of this study are summarized in Table 3. Of note is that seven of the nine boilers would have complied with the 1978 NSPS performance test and that the same boilers would not have produced any periods of excess emissions on a 30-day rolling average basis. (The column headed "Maximum" is the number of 30-day rolling averages obtained from the data, each of which is a potential period of excess emissions.)

DISCUSSION

Long-term NO emissions data from nine pulverized coal-fired utility boilers were analyzed and compared with the 1978 NSPS. It is to be noted that none of these boilers are subject to the 1978 NSPS but were included in this study because they were equipped with certified continuous emission monitors (CEM).

Each utility submitted a data package consisting of:

- . Hourly-averages of NO, O₂ (or CO₂)*
- . CEM certification reports
- . Periodic coal analyses

*The 1971 NSPS allows the use of either O₂ or CO₂ as a dilution correction. CO₂ was used on only one boiler.

These packages were reviewed for completeness and legibility. Any discrepancies were resolved with the utility by telephone.

The hourly averages were entered on computer input sheets for analysis by a specially modified computer program. Plots were prepared of NO and O₂ (or CO₂) as a function of unit load prior to the site visits in order to identify any unusual results.

Site visits were made to seven of the nine boilers analyzed during this assignment. Details on an eighth boiler were obtained by letter. The purpose of these visits was to hold detailed discussions with the appropriate station personnel. The topics discussed included:

1. Boiler Design
 - a. Boiler description
 - number of burners and burner arrangement
 - heat release rate
 - b. Operation of dual register burners and/or overfire air system
2. Boiler Operation
 - a. O₂ versus load
 - b. Heat rate
 - c. Steam temperature problems
 - d. Slagging/fouling characteristics
 - e. Unit availability/load limitations
 - f. Ash carbon characteristics
 - g. Tube wastage
 - h. NO excess emissions
3. CEM System
 - a. Make and model
 - b. Sampling location
 - c. Data reduction procedure
 - d. Recertification
 - e. Calibration procedure
 - frequency, out-of-calibration flag, corrective action
 - f. Quality assurance program
4. Coal Supply
 - a. Source
 - b. Nominal characteristics and variability

If the site visit identified some of the data as being of questionable validity, then a revised computer analysis was performed with these data deleted.

The analysis is illustrated by the results computed for Mill Creek Unit 3. Figure 1 are the boiler characteristics (NO and O₂) developed as a function of load. These characteristics were computed by sorting the data

into 10 load "cells" and averaging the associated values of NO and O₂. Of note is the relatively flat NO emission factor across the load range. Apparently, the decrease in O₂ with load is sufficient to nearly offset the higher heat release rate. Figure 2 is the load probability distribution which is representable only in terms of its median value of 270 gross MWe, which is 63.5 percent of rating. Figure 3 indicates that the hourly averaged NO is normally distributed with a mean of 215 ng/J and a standard deviation of 27 ng/J.

Muskogee Units 4 and 5 are nominally identical boilers, yet their NO characteristics are significantly different (Figure 4). Of note is that the maximum NO emission factor occurs at less than full load and Unit 5 indicates a significant NO decrease with loads above 200 gross MWe. The difference in O₂ characteristics (Figure 5) was deemed to be insufficient to completely resolve the difference in NO.

The operation of base-loaded units, as illustrated by Homer City Unit 3, deserves special attention. As noted from Table 3, this unit would have exceeded the 1978 NSPS on all occasions, which is attributed to its mode of operation. An examination of the load probability distribution for this unit (Figure 6) indicated that 85 percent of the time it was operating at or above 94 percent of the rated generator gross output.

By comparison, for units which operate with load cycles, it is possible to "average in" periods of potentially lower emissions at lower loads. This is illustrated by the NO probability for Unit A which shows (Figure 7) that 38 percent of the hourly averaged data points were above the 1978 NSPS for subbituminous coal. Despite this, Unit A would have complied with the 1978 NSPS performance test and would have had no periods of excess NO emissions.

The NO emissions from Council Bluffs 3 and San Juan 1 were low in comparison with the other boilers analyzed. Site visits to these two units indicated that they were being operated with the minimum air flow practical, and that both units were equipped with CO monitors as operating adjuncts. The reasons for this mode of operation were:

Council Bluffs 3--

- . Induced draft fan limitation at high load
- . Fuel economy

San Juan 1--

- . More stringent State of New Mexico NO_x limitation

In addition, neither unit was experiencing any unusual conditions due to low air operation; e.g., slagging, fouling, unburned carbon.

CONCLUSIONS AND RECOMMENDATIONS

The major conclusion established by this study was that seven of the nine boilers analyzed would have complied with the 1978 NSPS performance test requirements and would have produced no periods of excess NO emissions on a 30-day rolling average basis. The main exception (Homer City 3) is operated in a base-loaded manner.

It was also established that Council Bluffs 3 and San Juan 1 are low NO emission sources across their respective load ranges. This is attributed to their being operated with the lowest practical excess air with the assistance of a CO monitor.

It is recommended that the operation of these two units be documented in detail and then discussed with the respective boiler manufacturers to determine if this mode of operation could be adopted by other boilers.

It is also recommended that base-loaded units be considered as a separate category during the development of future performance standards. For these units there is limited operational flexibility to "average in" periods of potentially lower NO emissions at lower loads; i.e., the NO emission at rated load would have to be at or below the applicable standard.

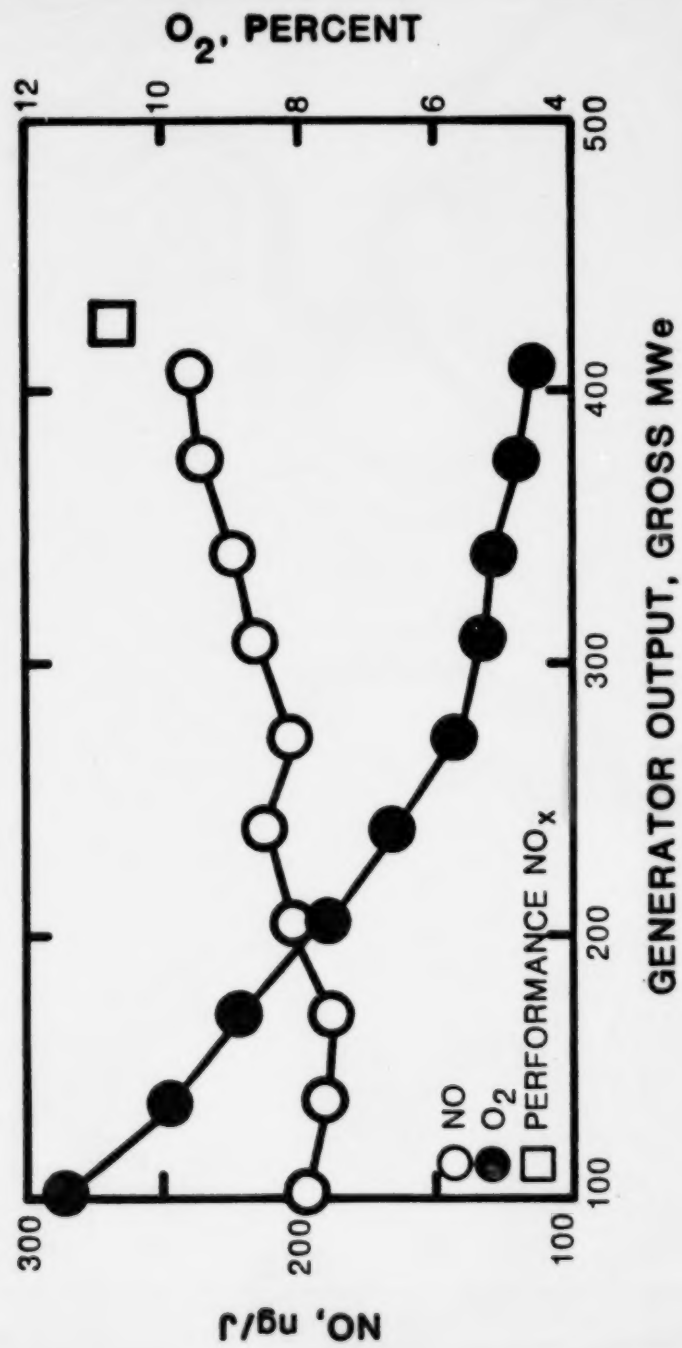


Figure 1. Boiler Characteristics - Mill Creek Unit 3

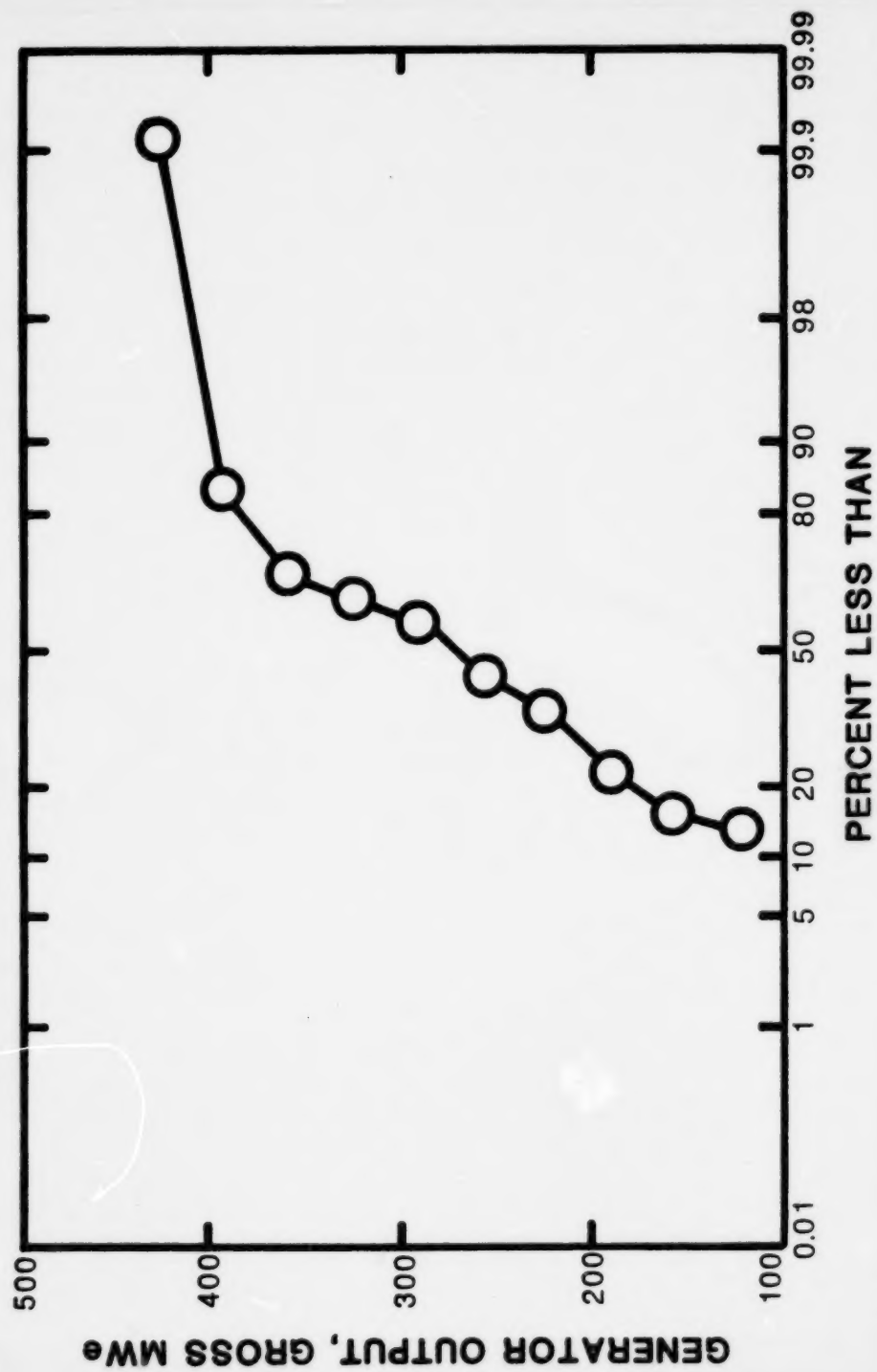


Figure 2. Load Probability - Mill Creek Unit 3

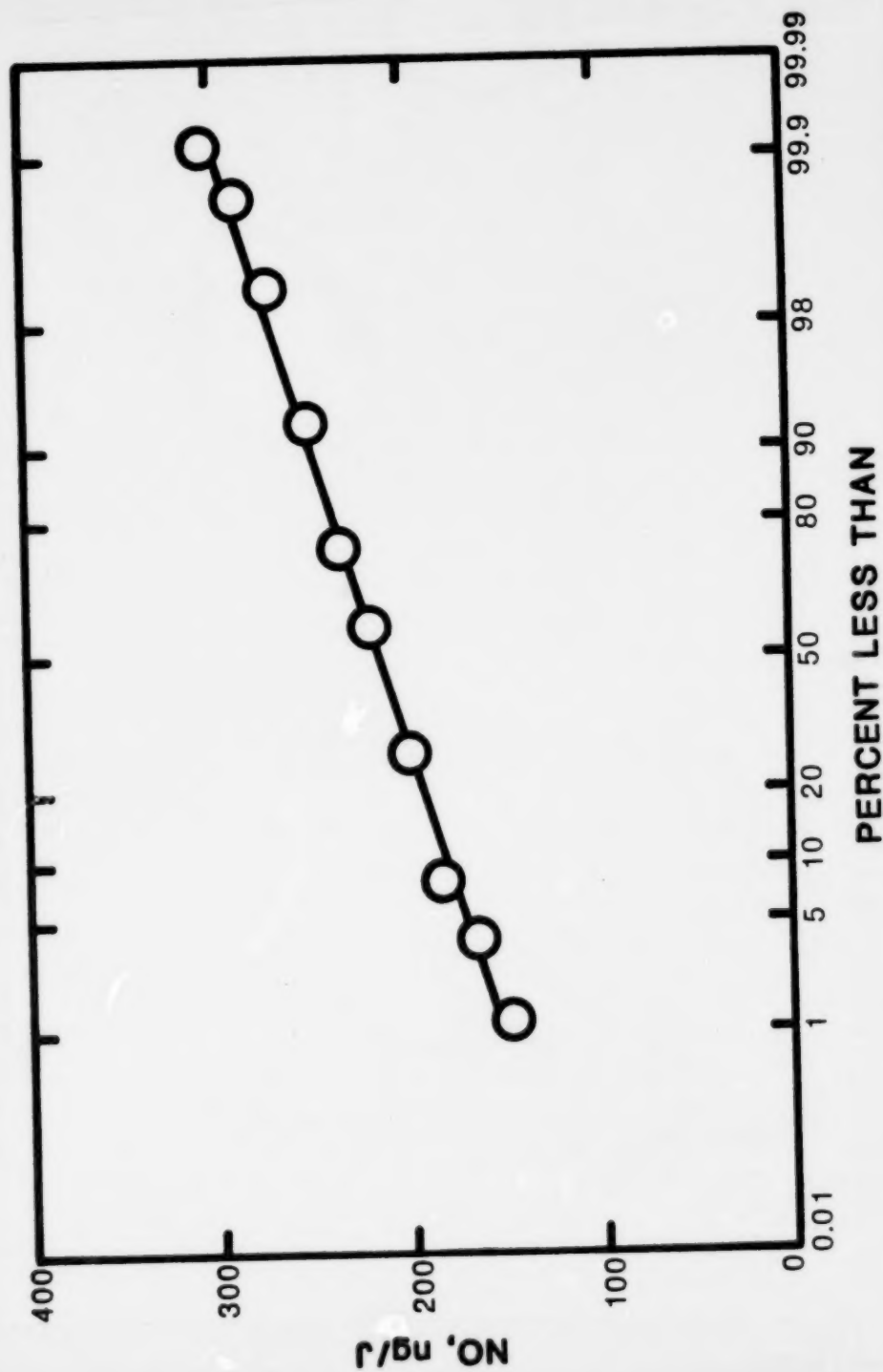


Figure 3. NO Probability - Mill Creek Unit 3

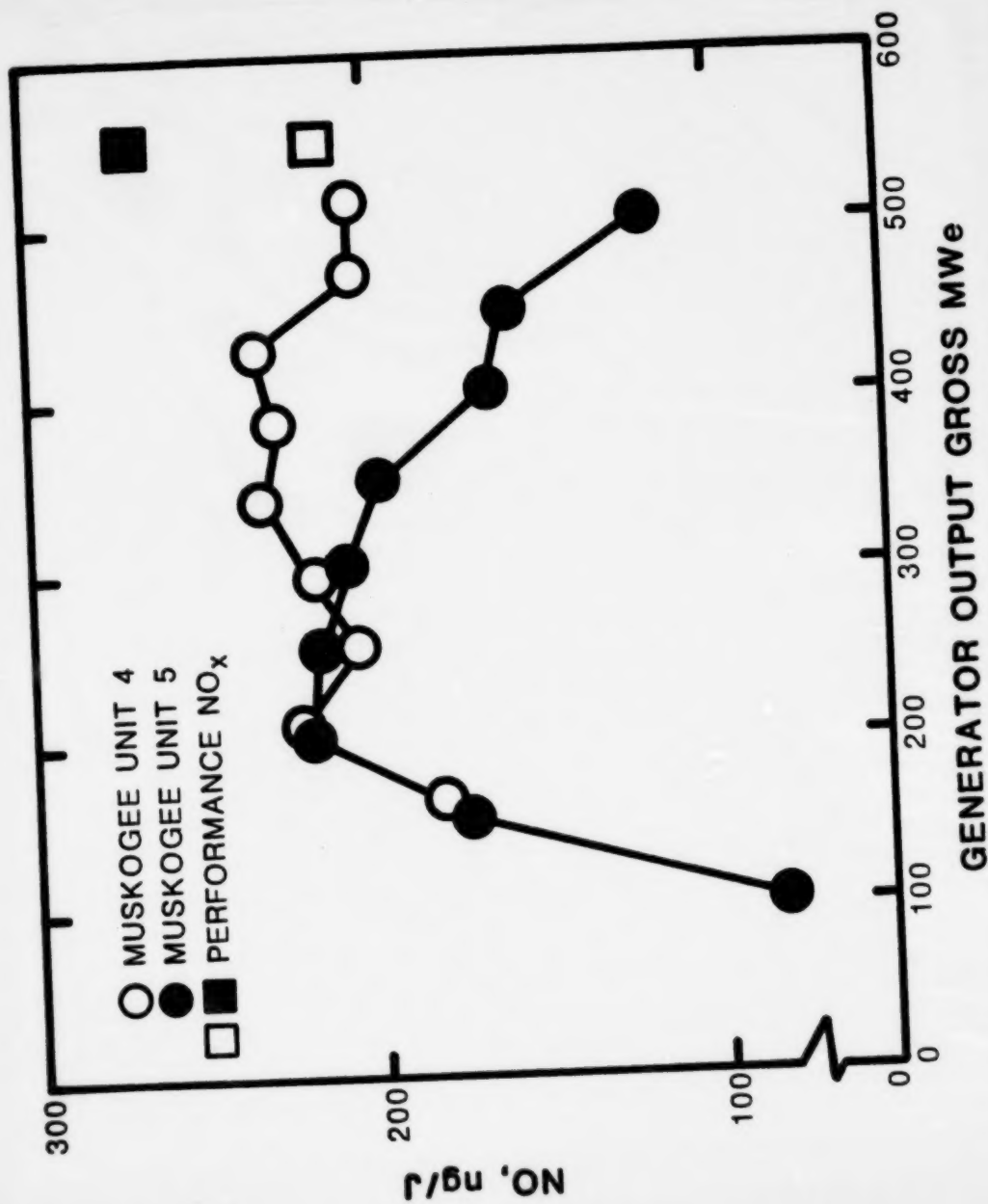


Figure 4. Comparison of NO Characteristic - Nominally Identical Units

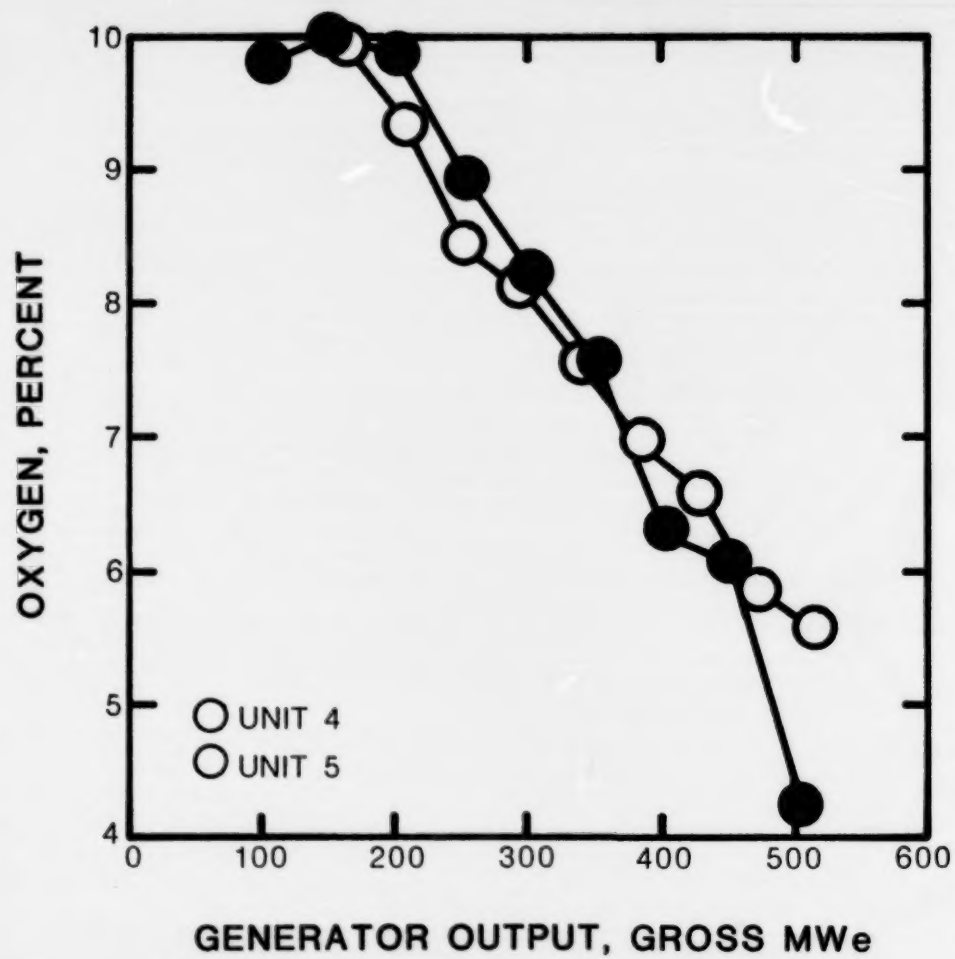


Figure 5. Muskogee Units 4 and 5 - Comparison of O₂ Characteristics

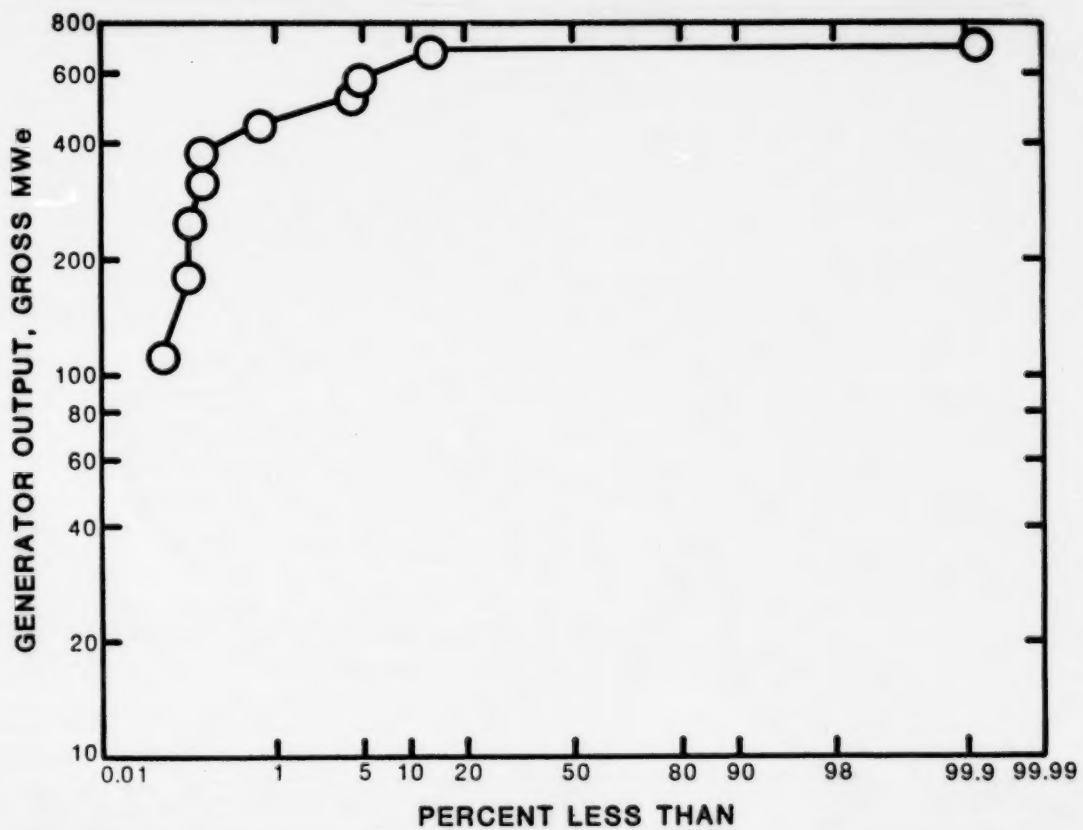


Figure 6. Load Probability - Base Loaded Unit (Homer City Unit 3)

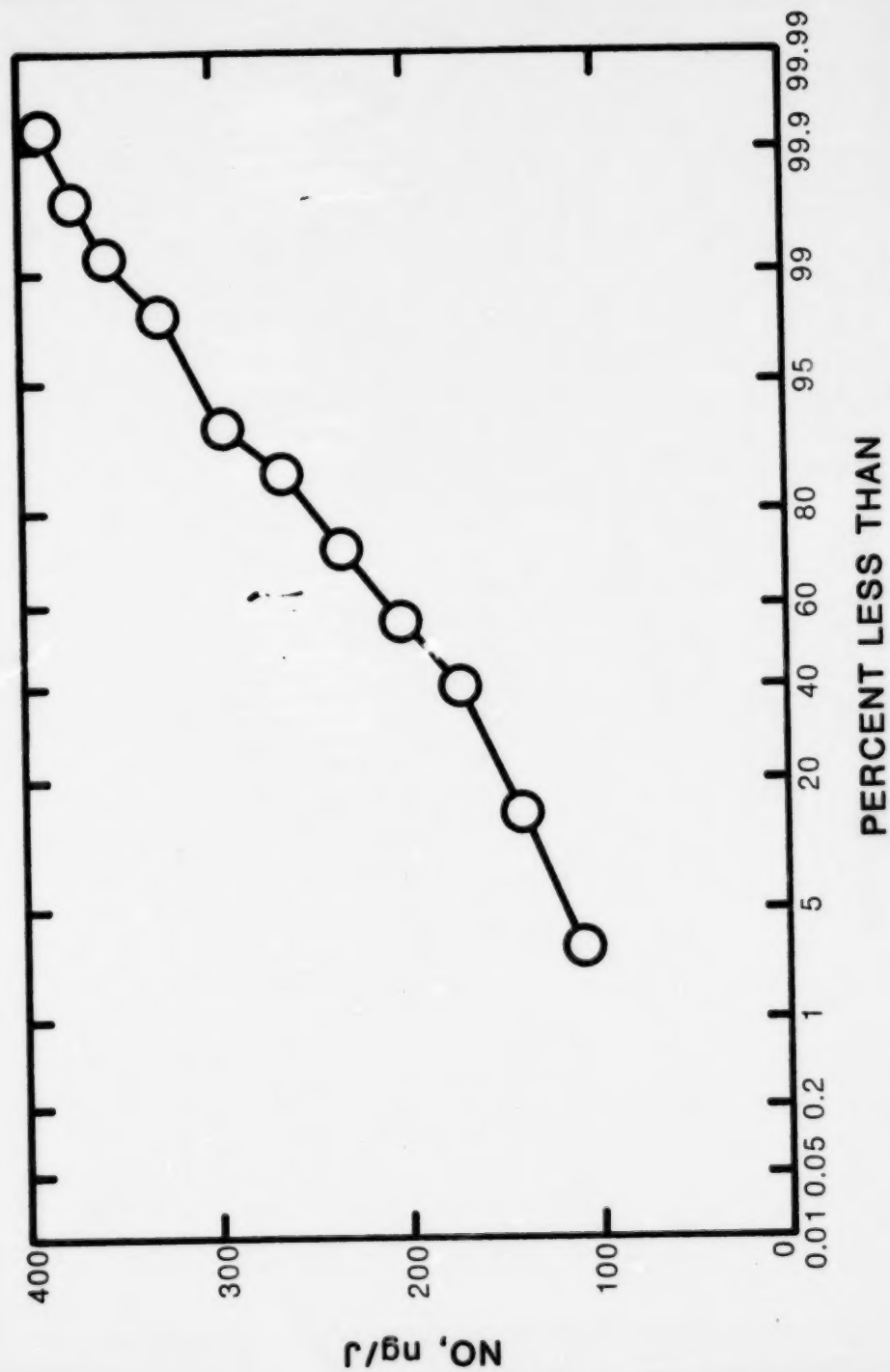


Figure 7. Unit A - NO Probability

TABLE 1. SUMMARY OF 1971 AND 1978 COAL NO_x NSPS

<u>1971</u>		
<u>Coal Type</u>	<u>ng/J</u> ^{NO_x}	<u>lb/10⁶ Btu</u>
Subbituminous	300	0.70
Bituminous	300	0.70
Lignite (Dakotas or Montana)	340	0.80
Other Lignites	260	0.60
3-Hour Averaging Period (Rolling or Block)		

<u>1978</u>		
<u>Coal Type</u>	<u>ng/J</u> ^{NO_x}	<u>lb/10⁶ Btu</u>
Subbituminous	210	0.50
Bituminous	260	0.60
Lignite (Dakotas or Montana)	340	0.80
Other Lignites	260	0.60
30-Day Rolling Average		

TABLE 2. BOILER PERTINENT INFORMATION

Utility	Station	Unit	Coal (1) Type	Boiler (2) Mfg.	Gross MWe	NO _x Controls (3)	Site Visit
Oklahoma Gas & Electric	Muskogee	4	Sub.	CE	550	Tang. + OFA	Yes
		5	Sub.	CE	550	Tang. + OFA	Yes
Omaha Public Power District	Nebraska City	1	Sub.	FW	575	Interstage air	No
Iowa Power & Light	Council Bluffs	3	Sub	B&W	720	DRB	Yes
Pennsylvania Electric	Homer City	3	Bit.	B&W	680	DRB	Yes
Louisville G & E	Mill Creek	3	Bit.	B&W	425	DRB	No (4)
Proprietary	---	A B	Sub. Sub.	CE CE	350 350	Tang. + OFA Tang. + OFA	Yes Yes
Public Service New Mexico	San Juan	1	Sub.	FW	360	OFA + DRB	Yes

(1) Sub. = Subbituminous
Bit. = Bituminous

(2) CE = Combustion Engineering
FW = Foster Wheeler
B&W = Babcock & Wilcox

(3) Tang. = Tilting tangential
OFA = Overfire air
DRB = Dual register burner

(4) Detailed information obtained by letter.

TABLE 3. ANALYSIS SUMMARY

Boiler	Coal Type (1)	1978 NSPS Performance ng/J	Number of Valid Days	1971 NSPS NO _x Exceedances Rolling	Block	1978 NSPS NO _x Exceedances Actual	Maximum
Muskogee 4 Revised	Sub.	208 207	94 78	17 17	6 6	0 0	65 49
Muskogee 5 Revised	Sub.	179 (3)	82 21	16 5	6 2	0 --	53 --
Nebraska City 1	Sub.	228(2)	31	30	12	2	2
Council Bluffs 3 Revised	Sub.	141 138	96 63	0 0	0 0	0 0	67 34
Homer City 3	Bit.	274(2)	61	161	60	32	32
Mill Creek 3	Bit.	210	54	0	0	0	25
Unit A	Sub.	189	75	75	31	0	46
Unit B	Sub.	158	78	2	2	0	49
San Juan 1	Sub.	175	57	0	0	0	28

(1) Sub. = Subbituminous

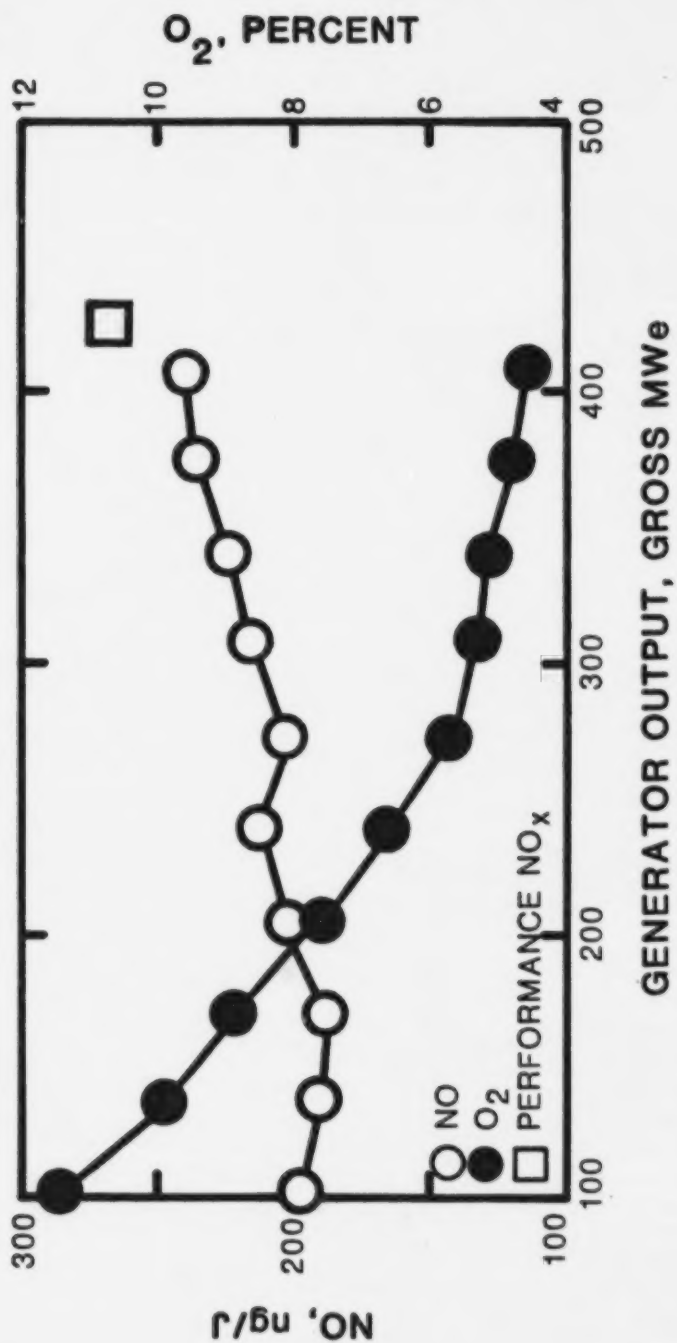
Bit. = Bituminous

(2) Would not have complied with 1978 NSPS performance test.

(3) Insufficient data to calculate 30-day rolling average.

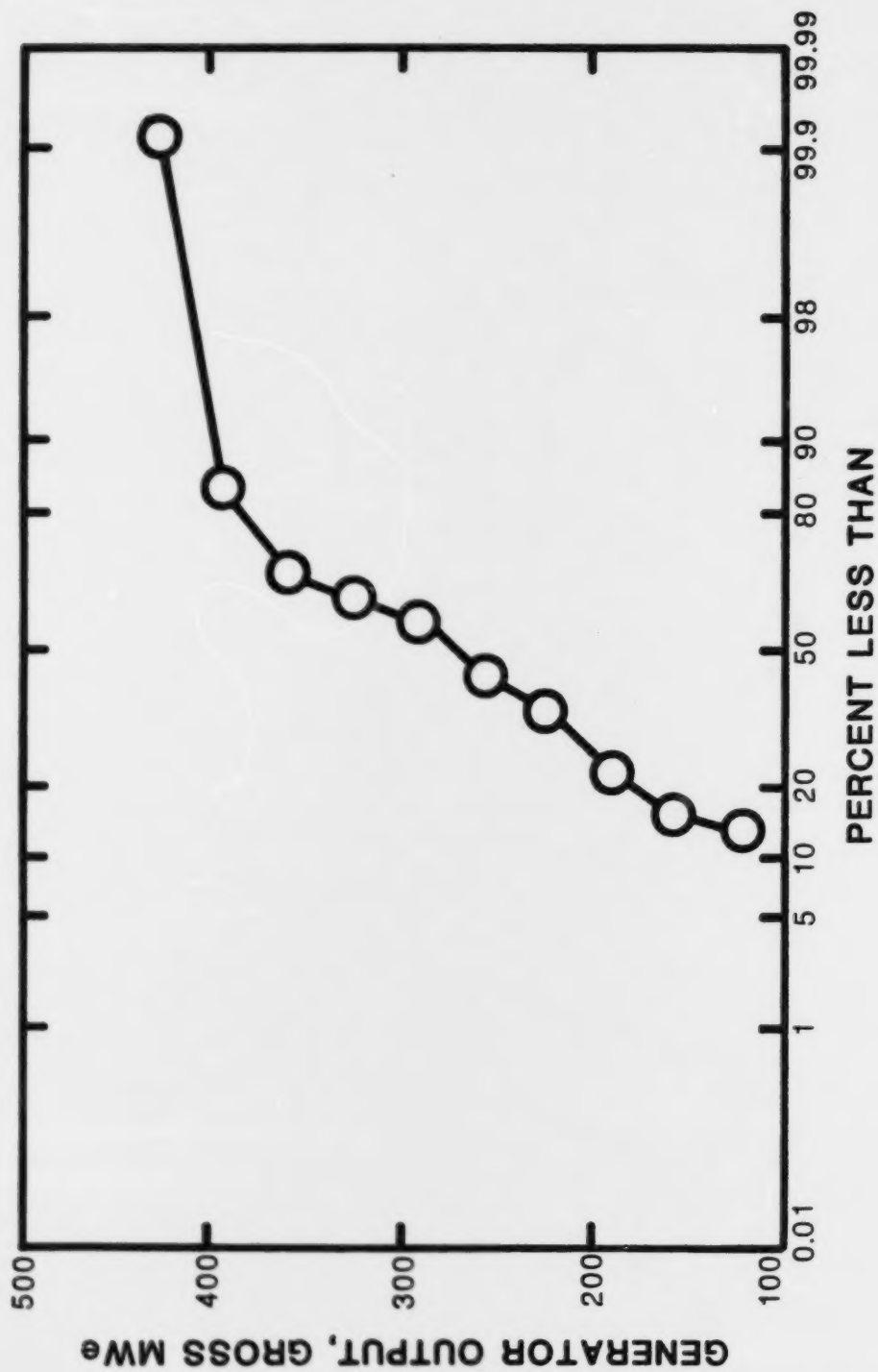
BOILER CHARACTERISTICS

MILL CREEK UNIT 3



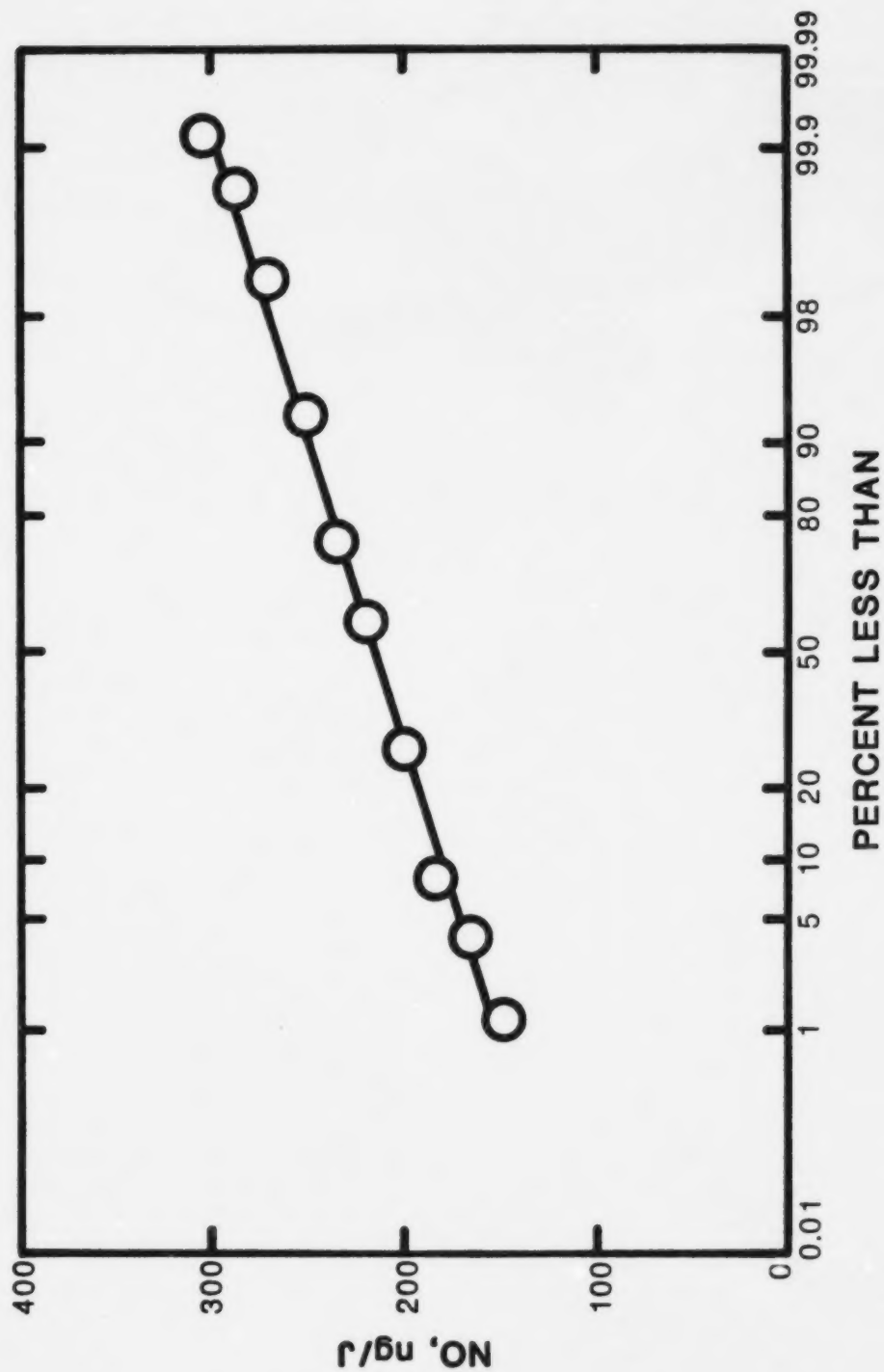
P-300

LOAD PROBABILITY
MILL CREEK UNIT 3



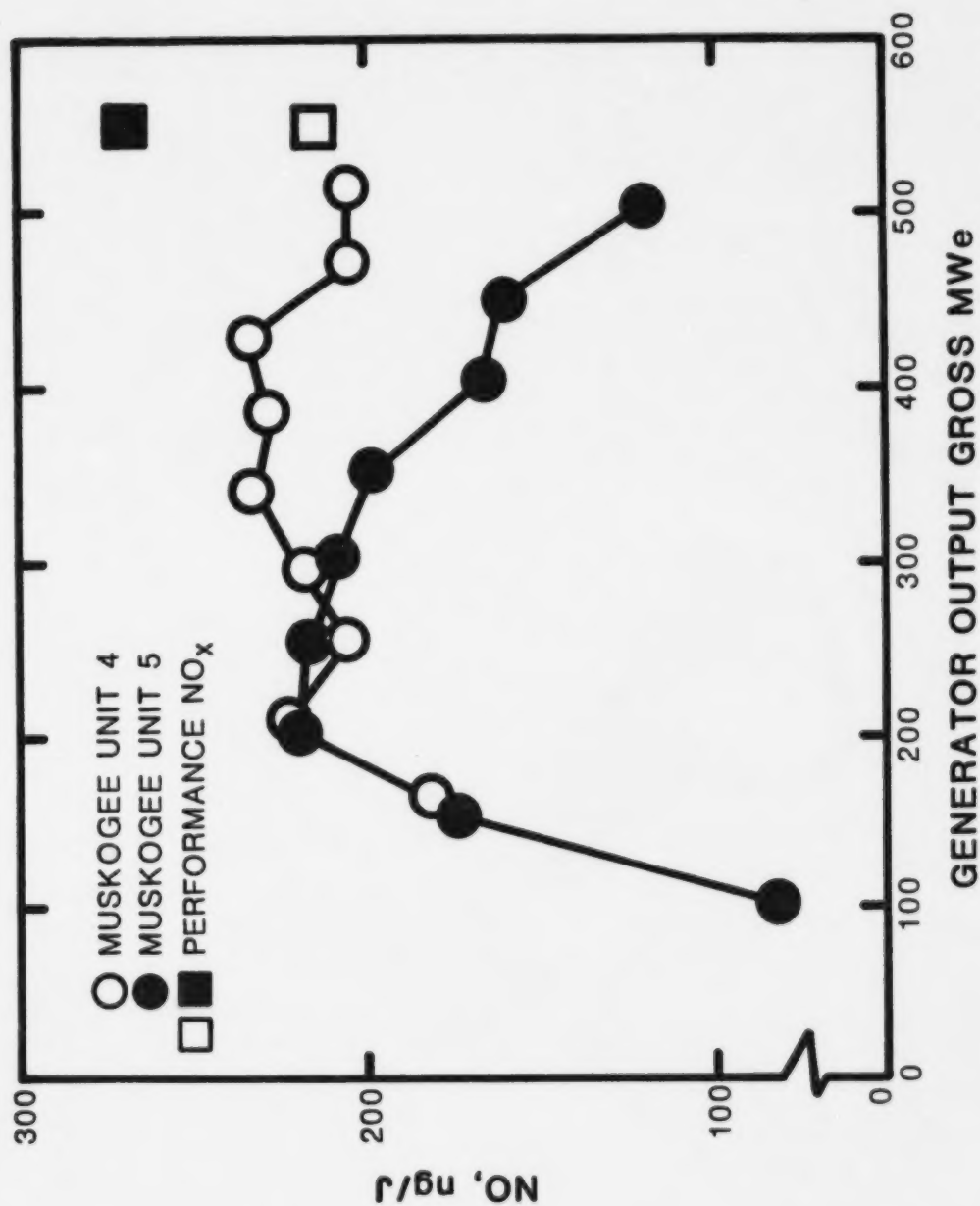
P-300

NO PROBABILITY
MILL CREEK UNIT 3



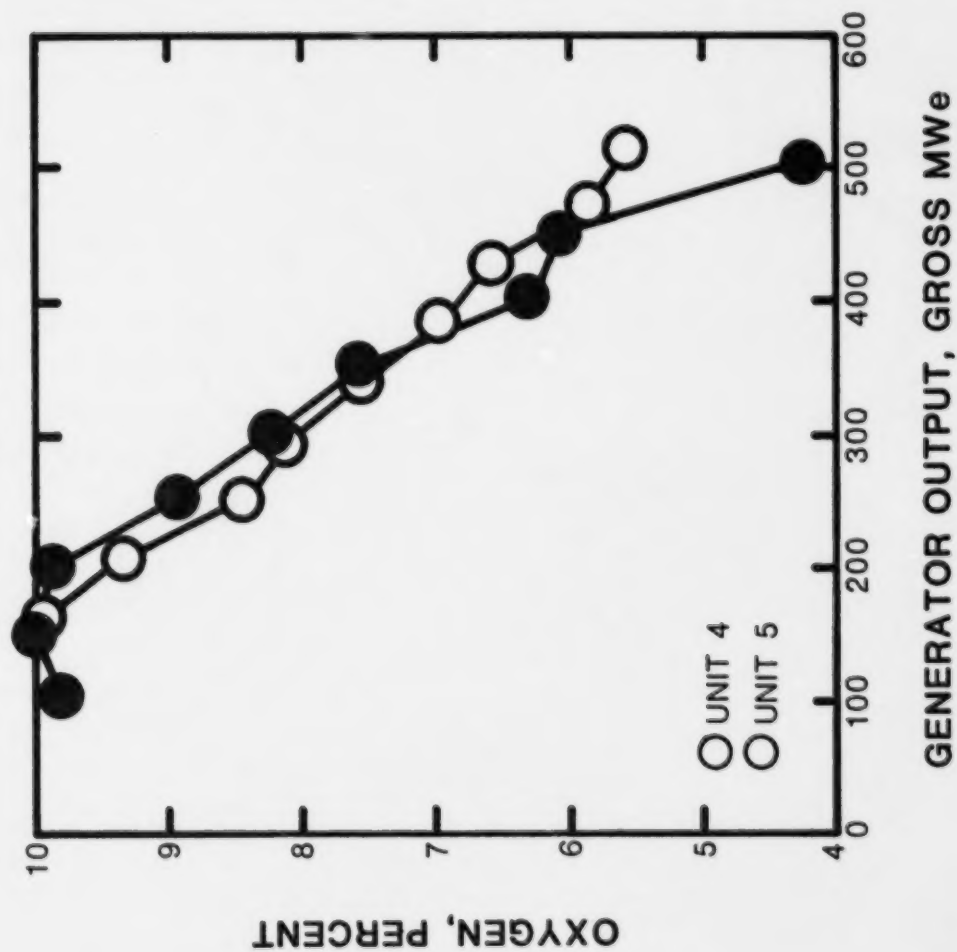
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COMPARISON OF NO CHARACTERISTIC - NOMINALLY IDENTICAL UNITS



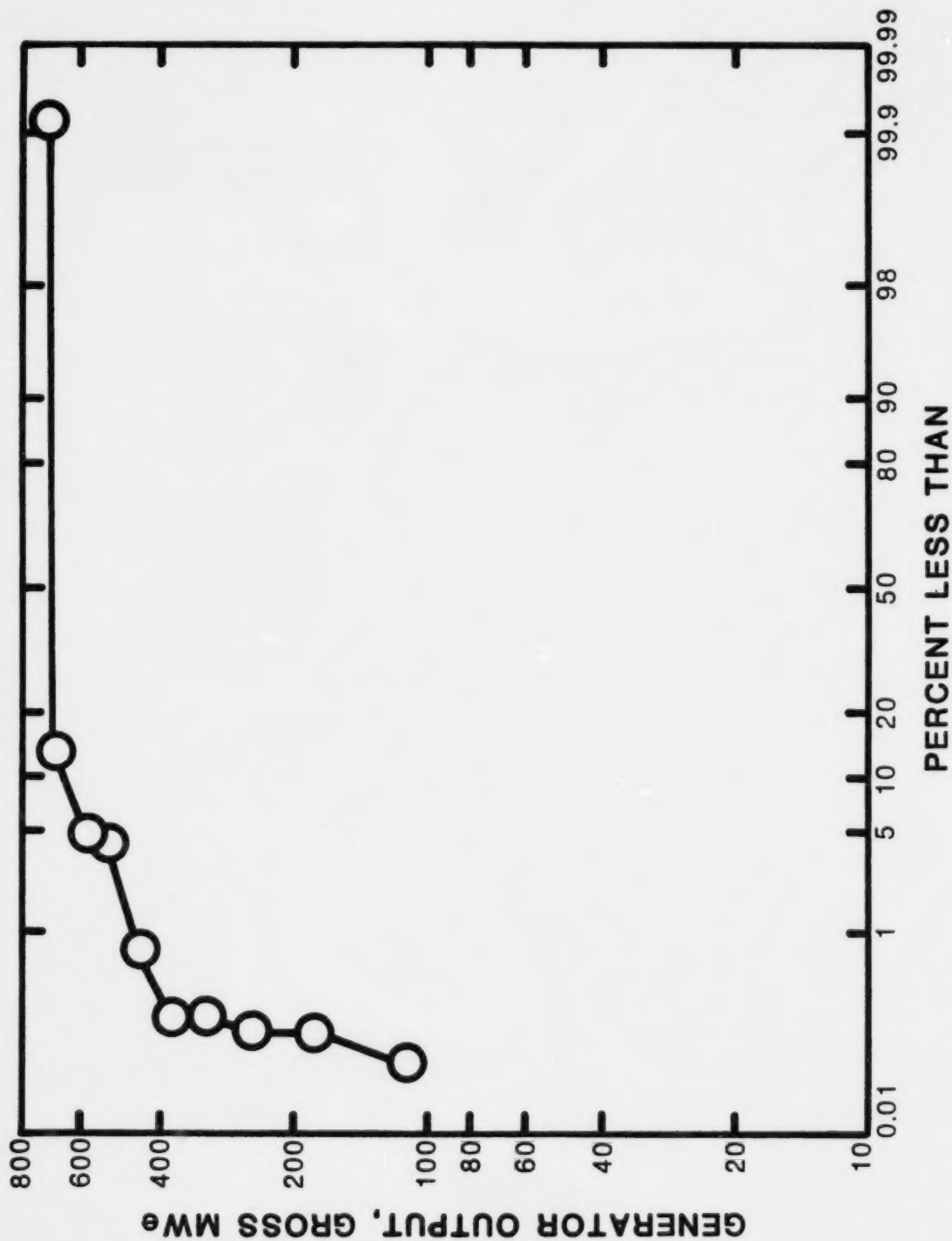
P-300

MUSKOGEE UNITS 4 AND 5 - COMPARISON OF O₂ CHARACTERISTICS



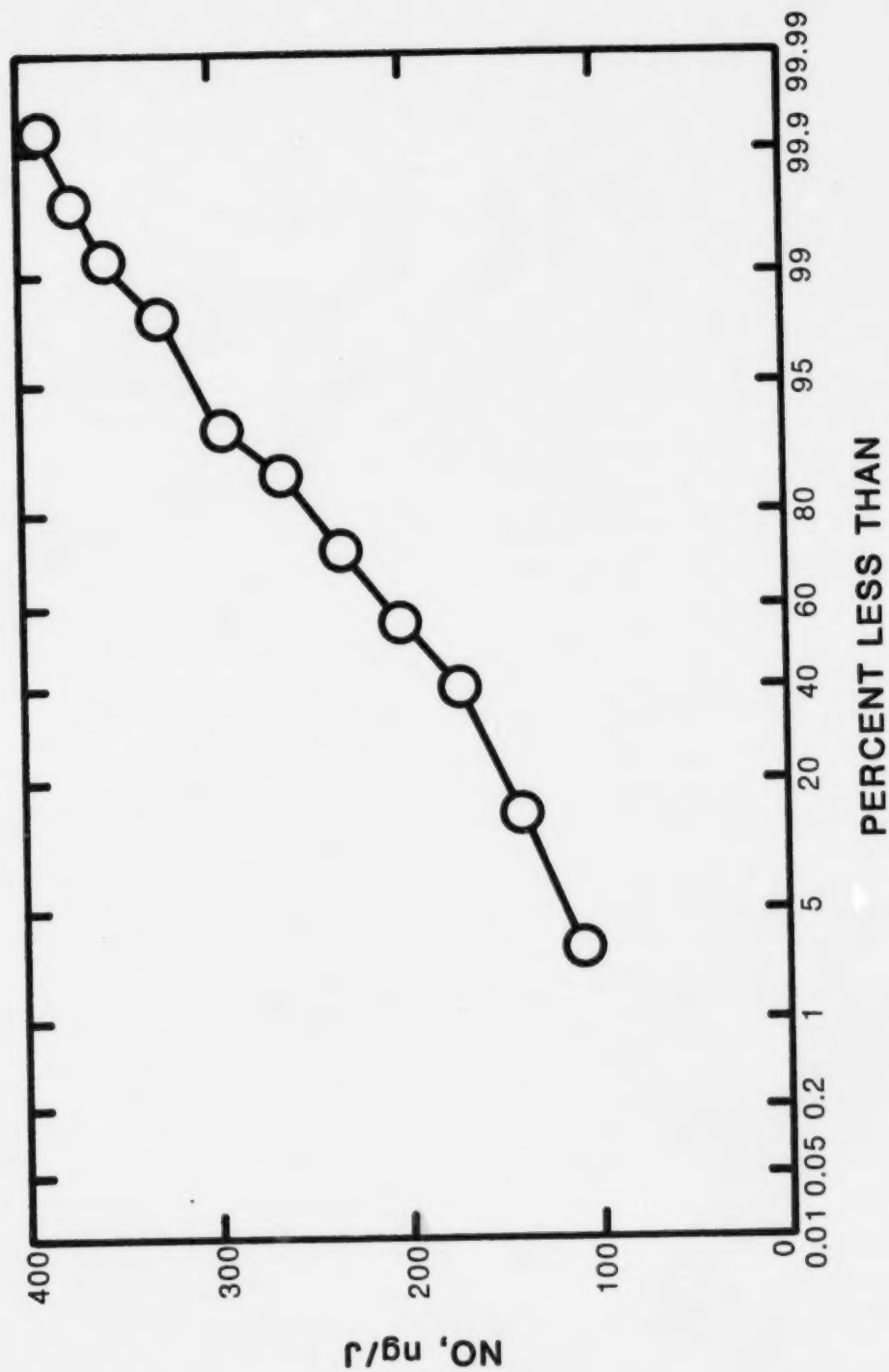
LOAD PROBABILITY - BASE LOADED UNIT

HOMER CITY UNIT 3



P-300

UNIT A - NO PROBABILITY



SESSION IV

LOW-NO_x COMBUSTION DEVELOPMENT
Chairman, G. Blair Martin
EPA, IERL/RTP

NO_x EMISSIONS CONTROL WITH THE DISTRIBUTED MIXING BURNER

Part I. Field Evaluation on an Industrial-Size Boiler

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ABSTRACT

The distributed mixing burner (DMB) is a low NO_x pulverized coal burner for wall-fired applications. It consists of a circular burner with outboard air ports. Low NO_x emissions are achieved by injecting a portion of the combustion air through the ports so that the circular burner operates under reducing conditions. An overall oxidizing environment is maintained in the furnace to minimize slagging and corrosion. Field operation of the DMB is being evaluated on a four-burner industrial-size boiler with a steam raising capacity of 98 kg/hr (215,000 lb/hr). Part I of this paper presents the results of baseline field tests with the original equipment burners and research furnace tests of a prototype DMB. Field tests of the DMB are in progress.

INTRODUCTION

The low cost and availability of coal make it the preferred fuel for most large combustion systems including industrial and utility boilers. However, the emissions of NO_x and other pollutants from coal combustion are generally considerably greater than from combustion of oil or gas. It has been estimated that increases in coal usage will result in an 80 percent increase in NO_x emissions by the year 2000 even if current NO_x control technology is applied to all operating systems (1). Maintaining or improving air quality will require the development and application of advanced NO_x control techniques. Several advanced NO_x control techniques are now being developed. Combustion modification through the installation of low NO_x burners is one of the most promising techniques for reducing NO_x emissions without increasing capital and operating costs or reducing efficiency significantly.

For the last several years the EPA has been assisting in the development of a low NO_x pulverized coal burner for wall-fired applications. This distributed mixing burner (DMB) consists of a circular burner surrounded by outboard tertiary air ports. The DMB concept involves staging the combustion process to minimize NO_x emissions while maintaining an overall oxidizing atmosphere in the furnace so as to have minimal impact on furnace slagging and corrosion. NO_x production from fuel nitrogen compounds is minimized by

driving a majority of the compounds into the gas phase under fuel-rich conditions and providing a stoichiometry/temperature history which maximizes the decay of the evolved nitrogen compounds to N_2 . Thermal NO_x production is also minimized by heat loss from the fuel-rich zone which reduces peak temperatures.

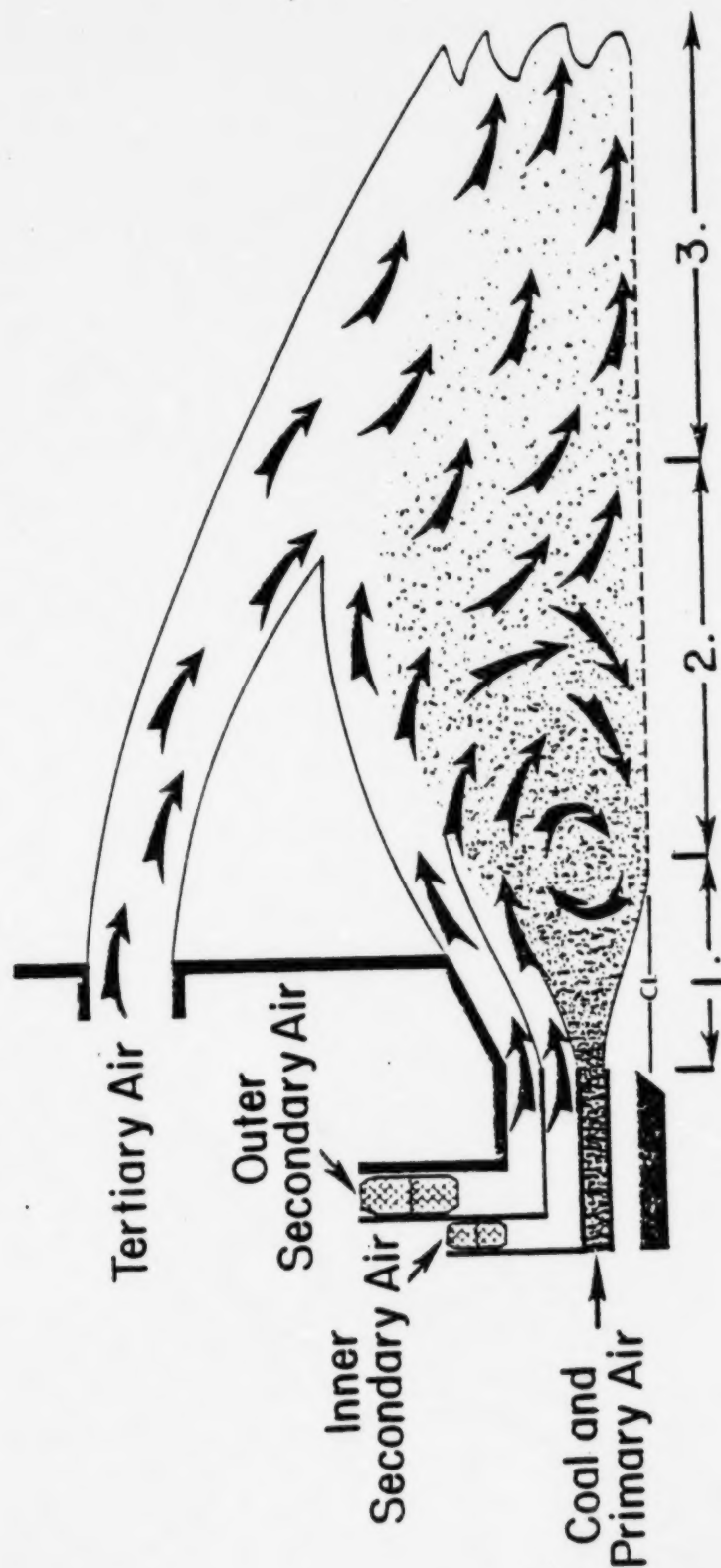
A schematic representation, illustrating how the DMB design sequentially stages the fuel/air mixing, is shown in Figure 1. The combustion process occurs in three zones. In the first zone pulverized coal transported by the primary air combines with the inner secondary air to form a very fuel-rich (30 to 50 percent theoretical air) recirculation zone which provides flame stability. The coal devolatilizes, and fuel nitrogen compounds are released to the gas phase. Outer secondary air is added to the second "burner zone" where the stoichiometry increases up to about 70 percent theoretical air. This burner zone stoichiometry has been found to be the optimum range for reduction of fuel-bound nitrogen compounds to N_2 (2). Air to complete the combustion process is supplied through tertiary ports located outside the burner throat. This allows substantial residence time in the burner zone for decay of bound nitrogen compounds to N_2 and radiative heat transfer to reduce peak temperatures. The tertiary ports surrounding the burner throat provide an overall oxidizing atmosphere in the burner zone.

Figure 2 illustrates the installation of a typical DMB design in a wall-fired furnace. The design shown has an annular coal nozzle and registers for secondary air flow rate and swirl control. Other designs are also possible. For example, DMBs have been constructed and tested with central coal nozzles and with single or double secondary air passages with swirl blocks and swirl vanes.

Initial development of the DMB was conducted at the International Flame Research Foundation (IFRF) under EPA Contract 68-02-0202. This included proof of concepts tests in a research furnace firing at 2.5 MW (8.5×10^6 Btu/hr). Additional development and scale-up tests were conducted at Energy and Environmental Research Corporation (EER) under EPA contracts 68-02-1488 and 68-02-2667. Six DMB configurations were evaluated in two research furnaces to determine the effects of design parameters and operating conditions on flame characteristics, combustion efficiency and NO_x emissions. These burners ranged in capacity from 3.6 MW (12.5×10^6 Btu/hr) to 29 MW (100×10^6 Btu/hr), and were tested as single burners. In addition, a 2×2 array of 3.6 MW (12.5×10^6 Btu/hr) burners was also tested. Under optimum conditions, NO_x emissions less than 65 ng/J ($0.15 \text{ lb}/10^6 \text{ Btu}$) were obtained (3). The results of these tests were analyzed to determine design criteria which can be used as the basis for future DMB designs (4).

This initial DMB development appeared very promising. However, direct application to field operating systems was limited by the following factors:

1. The development DMBs were research burners. They were designed to achieve the lowest possible NO_x emissions commensurate with flame stability and combustion efficiency constraints. They did not utilize commercial burner components and were not capable of long-term operation in a commercial system.



1. Very fuel-rich zone (average stoichiometry 40%)
2. Progressive air addition zone (overall stoichiometry 70%)
3. Final air addition zone (overall stoichiometry 120%)

Figure 1. DMB concept.

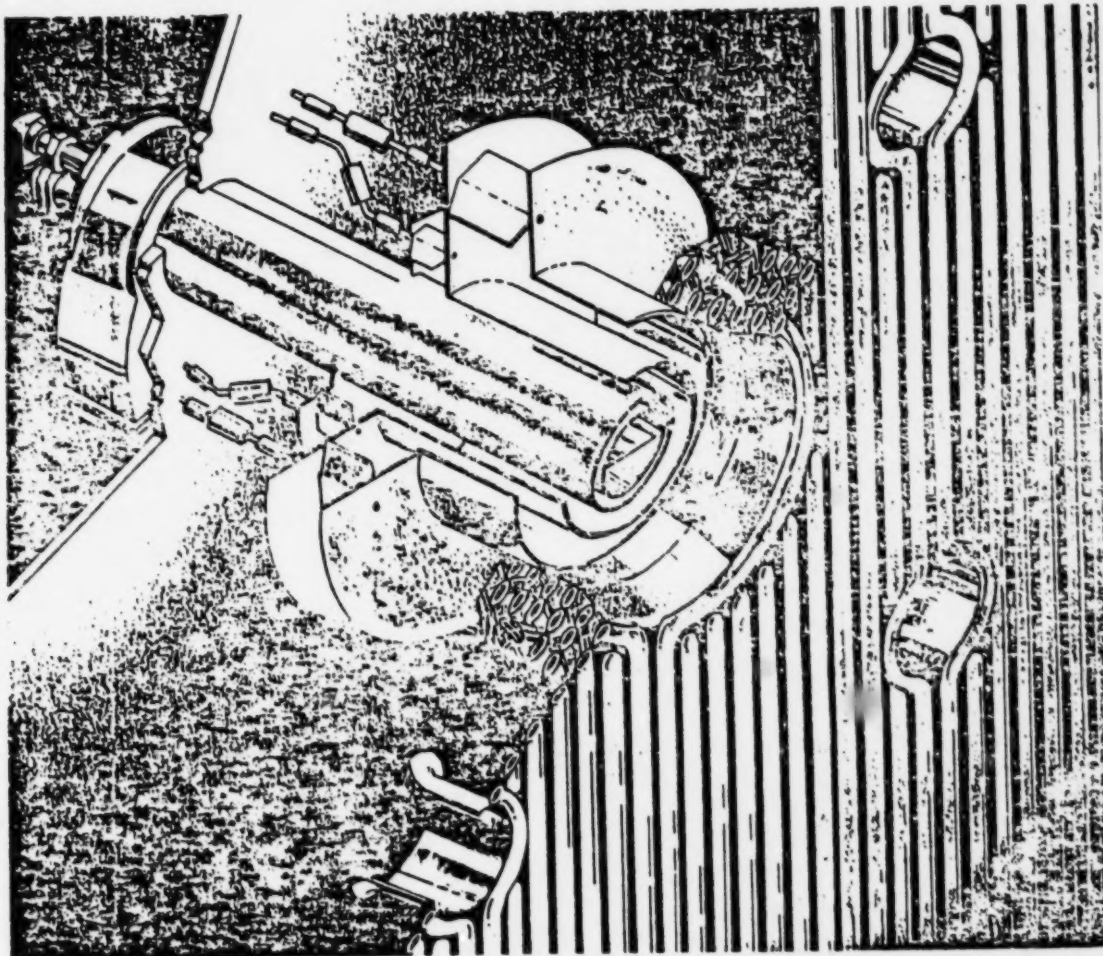


Figure 2. Distributed mixing burner.

2. The DMBs were tested in research furnaces only. It is well known that the performance of pulverized coal burners depends on furnace environment. Thus satisfactory performance in a research furnace does not necessarily ensure satisfactory field performance.

Application of the DMB concept to field operating systems requires that DMBs be designed and constructed using commercial burner components and field tested in commercial steam generating systems. A field evaluation of a DMB is being conducted on an industrial size boiler under EPA contract 68-02-3127 (5). Part I of this paper discusses the progress on this field evaluation.

The field evaluation of the DMB has progressed through burner installation in the host boiler. The design and performance of the host boiler with the original equipment burners are discussed in the following section. A prototype DMB was designed by integrating the DMB design criteria developed through research furnace tests with Foster Wheeler burner components. This burner was tested in a research furnace to optimize its design and to verify that performance met host boiler requirements. The burner design and test results are discussed in the third section. Based on the successful completion of the prototype burner tests, DMBs were installed in the host boiler and are now operating unstaged. The design and installation of the field operable burners are discussed in the fourth section.

When the initial field evaluation has been completed, the DMB performance will have been evaluated at one burner capacity in one field operating furnace. However, commercial burners are manufactured in a range of capacities and are operated in furnaces which vary in design. Part II of this paper discusses the effects of burner scale and furnace confinement on DMB performance. Data are presented from tests of several DMB designs varying in capacity from 3.6 MW (12.5×10^6 Btu/hr) to 29 MW (100×10^6 Btu/hr) firing in three research furnaces with varying geometry and thermal environments.

HOST BOILER DESIGN AND PERFORMANCE

The boiler selected for field evaluation of the DMB is Pearl Station, which is owned and operated by Western Illinois Power Cooperative (WIPCO). Figure 3 shows the general arrangement of the unit and Table 1 lists the design and operating characteristics. Although this unit is a utility boiler, its capacity and design are similar to many industrial boilers. The maximum continuous rating is 98×10^3 kg/hr (215,000 lb/hr) of steam. The electrical power output at maximum continuous rating is 20 MW. The steam temperature is 485°C (905°F) and the steam pressure is 60.7×10^6 dynes/cm² (880 psi). There is no reheat or economizer, and a portion of the steam is generated in the convective pass. The unit was erected in 1965 by Foster Wheeler and was equipped with four Intervane burners in a 2 x 2 array. The Intervane burner is Foster Wheeler's commercial pre-NSPS burner.

To establish the operating requirements for the DMBs and to determine the baseline boiler performance and emissions, a comprehensive field test of the WIPCO unit was conducted. The specific objectives were to evaluate the following:

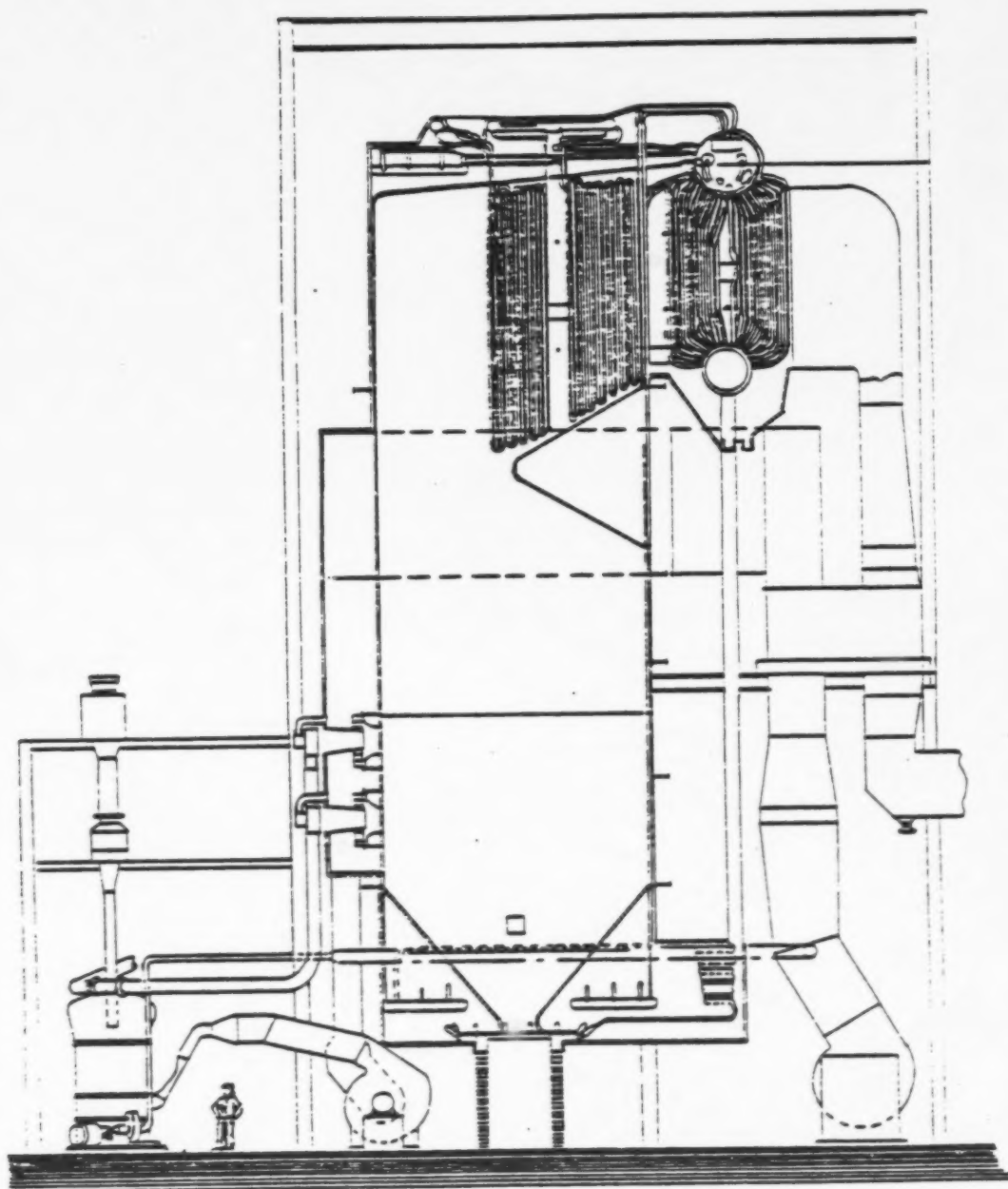


Figure 3. WIPCO Pearl Station.

TABLE 1. INITIAL DEMONSTRATION SITE CHARACTERISTICS (WIPCO)

PARAMETER	VALUE
<u>Boiler</u>	
Configuration	Single Wall-Fired
Capacity	MCR
	Peak
	98 x 10 ³ kg/hr (215 x 10 ³ lb/hr)
	111 x 10 ³ kg/hr (245 x 10 ³ lb/hr)
<u>Burners</u>	
Type	Foster Wheeler Intervane
Array	2 x 2
Capacity	MCR
Throat Diameter	20 Thermal MW (69 x 10 ⁶ Btu/hr)
Spacing	Horizontal
	Vertical
	61 cm (24 in.)
	182 cm (71.5 in.)
	198 cm (78.0 in.)
<u>Furnace</u>	
Construction	Membrane Wall
Depth	6.28 m (20.6 ft)
Width	5.01 m (16.4 ft)
Burner Zone Liberation Rate (BZLR)	492 Thermal kW/m ² (156 x 10 ³ Btu/hr-ft ²)
<u>Fuel</u>	
Coal Type	Indiana Bituminous
Pulverizers	Type
	Number
	Foster Wheeler MB
	2
<u>Air Supply</u>	
Air Heater Type	Regenerative
Secondary Air Temperature	265°C (510°F)
Draft	Pressurized
Windbox Depth	132 cm (52 in.)
Burner Pressure Drop (nominal)	8.9 cm H ₂ O (3.5 in. H ₂ O)

1. Normal full-load operating conditions, performance and emissions.
2. Typical duty cycle and operating ranges as well as operating limits.
3. Effect of operating parameters on emissions.
4. Potential for NO_x reduction with combustion modifications but without component changes.

The baseline boiler tests are discussed in reference 6 and the results are summarized below.

Pearl Station is the principal power plant of WIPCO and normally operates base-loaded. Table 2 compares the performance measured at full-load in several tests over a nine-month period. Foster Wheeler has indicated that this performance is typical of many pre-NSPS units. Carbon utilization as measured by the carbon content of the particulate emissions using coal ash as a tracer was greater than 99.35 percent. CO emissions were less than 41 ppm and hydrocarbon emissions were less than 4 ppm. NO_x emissions ranged from 807 to 847 ppm, which corresponds to 395 to 412 ng/J (0.91 to 0.95 lb/10⁶ Btu). Since this is a pre-NSPS unit, it is exempt from NO_x emissions relations.

The WIPCO unit fires a variety of coals. Small quantities of coal are purchased from several mines based on cost (\$/10⁶ Btu) primarily. Since the beginning of this program, coals from four mines in Indiana, Illinois and Missouri have been fired. All are high-volatile bituminous coals but their compositions vary over a considerable range. The performance measured during the 30-day baseline test is shown in Figure 4. During this period the operators ran the plant in the normal manner adjusting load to meet demand and adjusting burner settings and excess air based on experience. Over the 30-day period, the coal was supplied from several piles at the power plant. Thus the coal composition varied over a wide range. Over the 30-day period, NO_x emissions averaged 849 ppm which corresponds to 413 ng/J (0.95 lb/10⁶ Btu). The standard deviation was 39 ppm or 4.6 percent.

Tests of several commercial burners have shown that the relationships between NO_x emissions, firing rate and excess air are approximately linear over the normal operating ranges. Consequently, data from the baseline field tests with normal burner settings were fitted to a linear relationship using a least squares technique. The result was the following correlation:

$$\text{NO}_x \text{ (ppm @ 0\% O}_2\text{)} = 2.30 \times (\% \text{ Full Load}) + 9.30 \times (\% \text{ Excess Air}) + 427.7$$

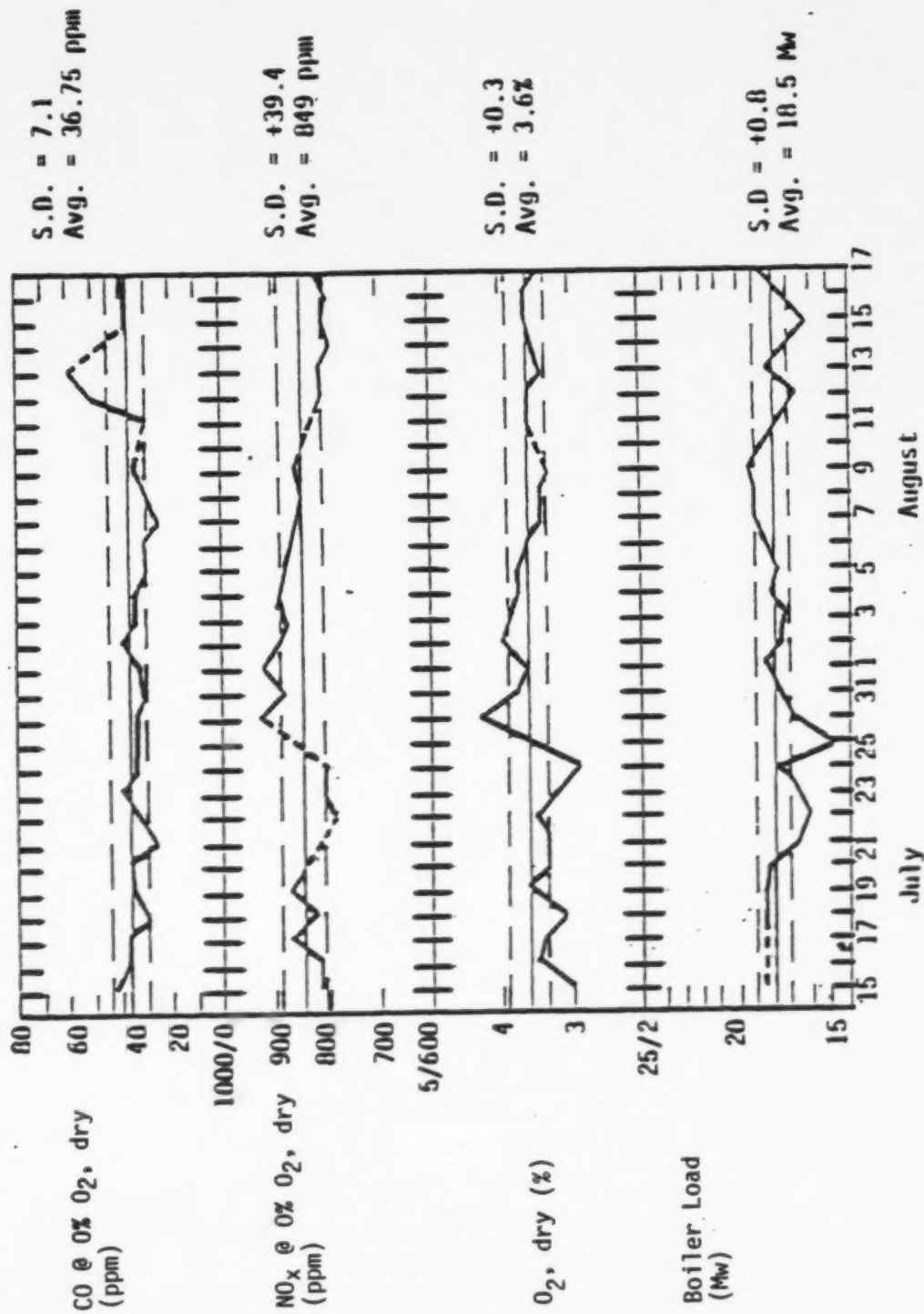
Figure 5 shows a load curve at the design point excess air (18 percent) and an excess air curve at full load. The data scatter is about ± 25 ppm. CO emissions, flame shape and flame stability were approximately constant over the load and excess air ranges shown in Figure 5.

The potential for NO_x reduction by burner and/or operating condition adjustment was evaluated. The data in Figure 5 shows that NO_x emissions

TABLE 2. NOMINAL BOILER OPERATING CONDITIONS AND EMISSIONS (WIPCO)

	(6/30/80 to 7/12/80)	(7/15/80 to 8/17/80)	(3/22/81 to 3/27/81)
Boiler Operating Conditions:			
Load (MW)	20.3	18.5	19.7
Excess Air (%)	18.9	20.5	23.2
Carbon Utilization (%)	99.54	99.36	99.67
Emissions*:			
NO _x @ 0% O ₂ (ppm)	826	847	807
CO @ 0% O ₂ (ppm)	41	37	32
SO ₂ @ 0% O ₂ (ppm)	3364	3299	4289
SO ₃ @ 0% O ₂ (ppm)	22	25	35
CO ₂ @ 0% O ₂ (%)	18.9	18.5	18.1
O ₂ (%)	3.4	3.6	4.0
Hydrocarbons@0%O ₂ (ppm)	1	1	4
Total Particulate (g/m ³ @ 0% O ₂)	88.6	65.8	109.1
kg particulate/kg ash in coal	0.965	0.828	0.812
HCN @ 0% O ₂ (ppm)			1
NH ₃ @ 0% O ₂ (ppm)			2

* Emissions corrected to 3% O₂ are 85.7% of the values listed.



Note: Boiler shut down from July 25 to July 30 for unscheduled outage unrelated to 30-day test.

Figure 4. 30-day test results (WIPCO).

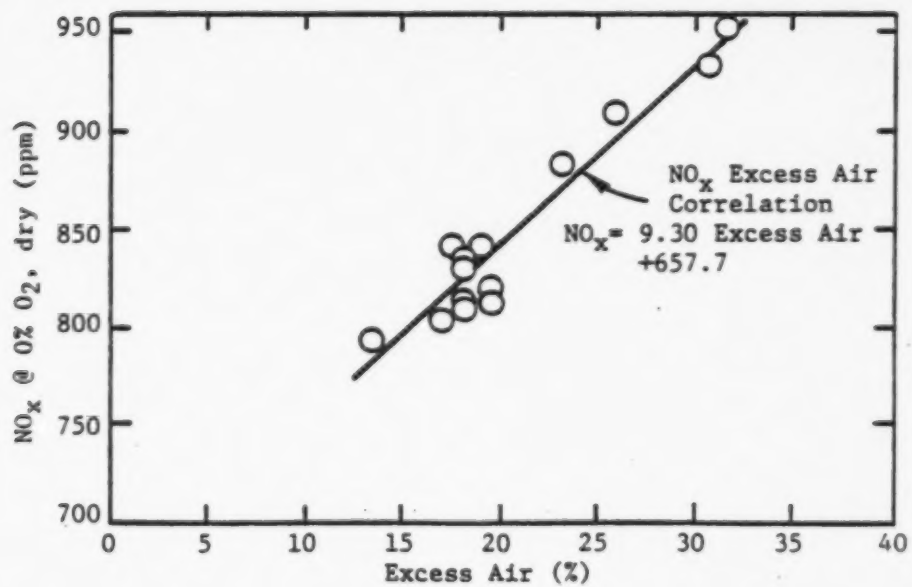
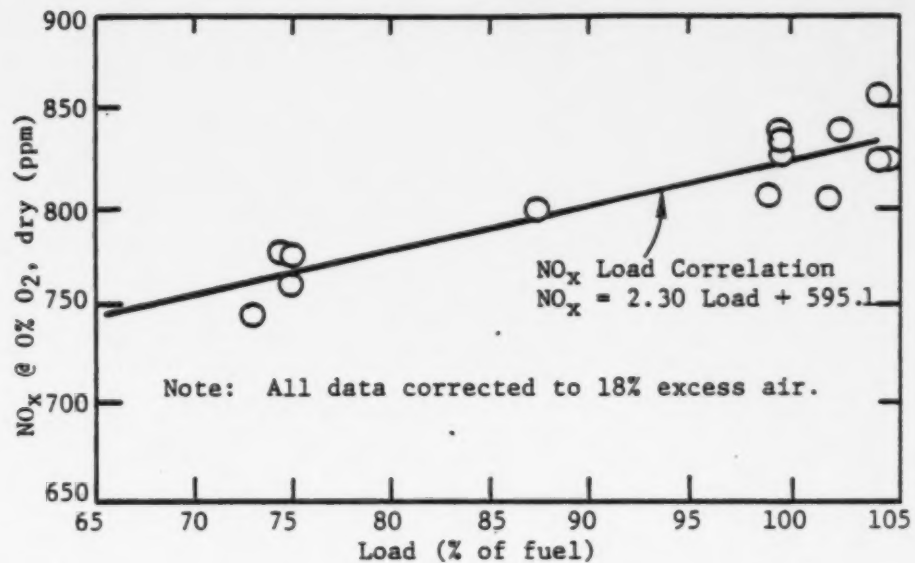


Figure 5. Load and excess air curves for WIPCO unit with original burners.

can be reduced by operating at low excess air. However, the boiler operators have established a minimum operating limit of 2.5 percent O_2 which corresponds to about 13 percent excess air. Burner adjustments were found to affect flame shape but to have little effect on NO_x emissions.

Biasing the coal supplied to the lower and upper burner rows reduced NO_x emissions. However, to achieve a NO_x reduction of 25 percent it was necessary to operate the lower burners under reducing conditions (88 percent theoretical air). This would not be satisfactory for sustained operation.

In summary, the performance of the WIPCO host boiler with the original equipment Intervane burners was found to be typical of pre-NSPS burner and boiler designs. The unit operates at base load with high combustion efficiency and produces high NO_x emissions. Adjustments to operating conditions and the burners were unsuccessful in reducing NO_x emissions to the levels expected with the DMBs.

PROTOTYPE DMB DESIGN AND PERFORMANCE

The development and testing of the prototype DMB for the WIPCO field evaluation has been completed. The objectives were to:

- Integrate the DMB design criteria and commercial burner components into a burner design meeting the requirements of the host boiler.
- Optimize the burner performance through iterative testing in a research furnace.
- Verify that all aspects of burner performance meet the host boiler requirements and that the burner is fully compatible with host boiler systems.

It is well known that burner performance is influenced by furnace environment. Since the basis of the DMB development is testing in a research furnace rather than a field operating boiler, some assurance is required that the research furnace test results are meaningful and can be related to field performance. The approach was to "calibrate" the research furnace against field performance by testing a commercial burner in the field as well as the research furnace. A field evaluation of the original equipment Foster Wheeler Intervane burner was conducted at WIPCO, and the results were discussed in the previous section. A similar Intervane burner was tested in the Large Watertube Simulator (LWS) at EER.* The test results were discussed in references 7 and 8. Comparison of the field and LWS test results indicated similar performance, especially in the key areas of flame shape and stability. However, NO_x emissions were lower and CO and smoke emissions were higher in the LWS than in the field operating boiler. This was attributed to the design of the LWS, which had significantly lower heat release/cooled surface area than the WIPCO furnace.

The initial prototype DMB was designed by integrating the DMB design criteria developed under EPA contracts 68-02-1448 and 68-02-2667, requirements of the WIPCO unit and Foster Wheeler burner components. The design of the central portion of the burner without tertiary air ports is illustrated

*The design of the LWS is discussed in Part II of this paper.

in Figure 6. The following Foster Wheeler burner components were incorporated into the burner designs:

- Annular Coal Nozzle.
- Telescoping Coal Nozzle for Primary Velocity Control.
- Registers for Swirl Control and Flow Shutoff.
- Air Hoods and Sliding Sleeves for Secondary Flow Rate Control and Measurement.
- Commercial Flame Scanning and Ignition System.

The coal and primary air enter the annular coal nozzle through a tangential inlet to provide swirl. The coal nozzle is a tapered annulus. The exit end of the coal nozzle is formed from two concentric cones. The inner cone can be moved axially to vary the exit area, and hence, the primary velocity. The outer portion of the coal nozzle is constructed of removable sections so that the overall length of the coal nozzle may be changed to vary the nozzle setback within the burner throat. There are two concentric secondary air passages supplied from a common windbox. Each is equipped with an adjustable register for swirl control, an axially movable sleeve for flow control and a perforated plate (air hood) for flow rate measurement. Pressure taps on both sides of each perforated plate allow the pressure drop to be measured and correlated with sleeve position and flow rate.

The portion of the burner inside the coal nozzle is termed the core, and is supplied with a small amount of cooling air from the windbox. A retractable ignition system, including spark ignition, an oil gun and an ignition flame scanner, are located in the core on the burner centerline. The main flame scanner views the flame through the inner secondary air passage.

The prototype burner was installed in a windbox along with four tertiary air ports and was tested in the LWS. These tests utilized a Utah bituminous coal which was used as a baseline fuel in previous burner tests. The tests were directed toward evaluation of burner performance under unstaged conditions (with the tertiary air ports closed). Some testing was also conducted under staged conditions. However, the testing was halted when the LWS furnace walls (which had already exceeded their design life) deteriorated. Analysis of these data showed that the operability, flame shape, smoke and CO emissions for the prototype DMB were comparable to the Intervane burner. However, NO_x emissions were much lower (as expected).

The LWS was rebuilt with several design changes to make burner performance in the LWS more representative of burner performance in field units as well as to facilitate testing. The original LWS was cooled on all surfaces, resulting in a thermal environment significantly cooler than that typically found in field operating boilers, such as the WIPCO furnace. To produce a thermal environment comparable to that found in the WIPCO furnace, the new LWS was partially lined with insulating refractory. The other major change

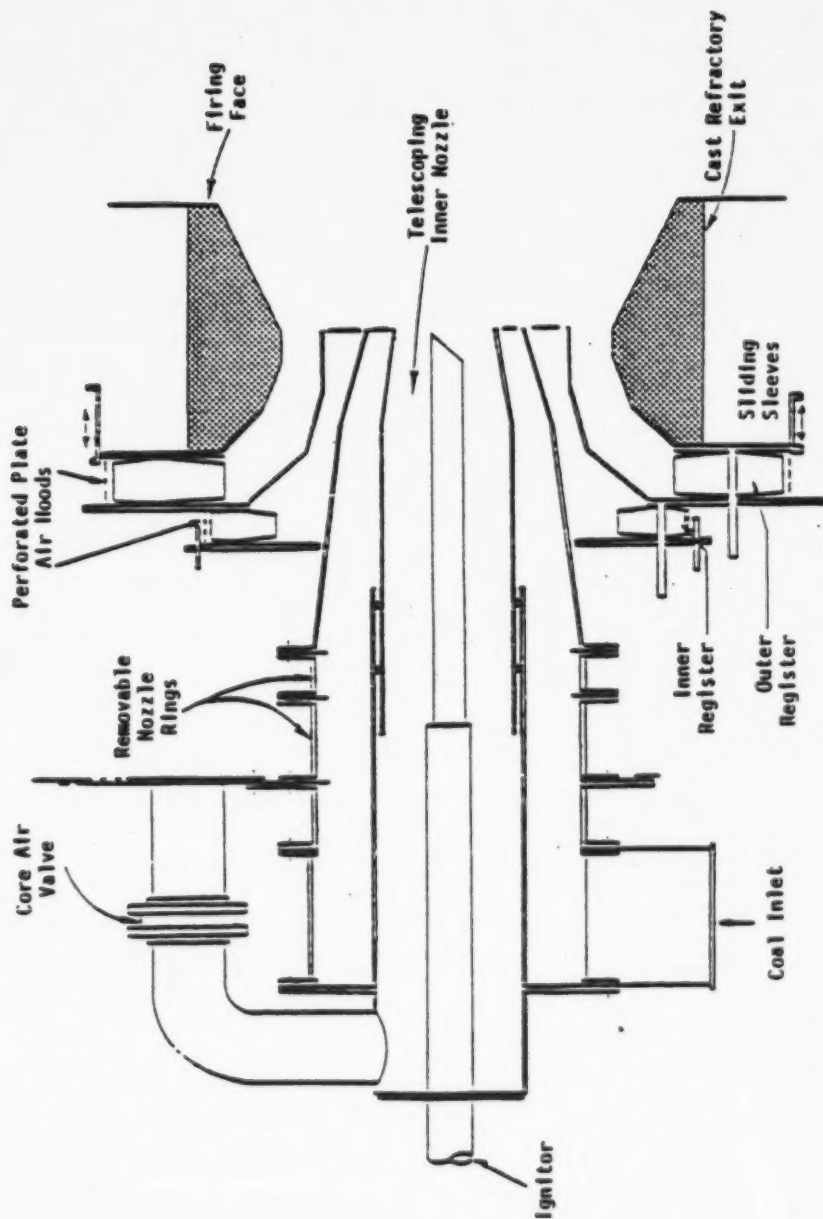


Figure 6. Initial prototype DMB based on Foster Wheeler design (tertiary ports not shown).

was the installation of an exhaust duct on the outlet of the LWS. The combustion products in the previous design were vented into the atmosphere from the top of the LWS. Because of the diffuse nature of the exhaust, the combustion products were sampled at the furnace outlet, or nose, with multiple probes. With the installation of an exhaust duct in the rebuilt LWS, more representative samples of the process could be obtained in the well-defined flow of a circular duct.

The prototype burner was retested in the new LWS under both unstaged and staged conditions with the Utah coal and an Indiana coal which was being fired at WIPCO. The NO_x emissions from these tests were nearly identical to the results obtained in the old LWS. However, the CO emissions were substantially lower and in the range of CO emissions from the baseline field test at WIPCO. These results suggest that the NO_x emissions from the DMB are insensitive to furnace thermal environment over the range investigated. Thus the NO_x emissions from the DMBs operated in the field are expected to be in the same range as the test results in the LWS. The results of these tests are discussed in reference 9.

Additional tests confirmed the earlier test results but showed that operation at the burner design point resulted in flame instability. As the combustion air was diverted from the secondary passages to the tertiary air ports, the flame became unstable at a burner zone stoichiometry of 85 percent theoretical air while the design point was 70 percent theoretical air. Stability limits were observed with some of the development DMBs, and performance was improved by adjusting nozzle and exit geometry.

Based on the original program plan, the next step would have been to modify and prototype burner geometry, retest in the LWS and thus iteratively search for the conditions which optimize performance. However, this would have resulted in a delay in the field installation of the DMBs by about one year (due to the outage schedule at WIPCO). The alternative was to incorporate a proven burner configuration known to be stable under staged operating conditions and to confirm burner performance in the LWS while preparations were being made for the field installation. The Foster Wheeler Controlled-Flow Burner has been operated in Japan with burner zone stoichiometries comparable to the DMB but using overfire air ports instead of tertiary air ports. Thus it was decided to incorporate the Foster Wheeler geometry into the DMB.

The modified prototype DMB was tested in the LWS under unstaged and staged conditions. The unstaged tests verified that flame stability and shape were satisfactory over the WIPCO boiler operating range. Thus the DMBs can be operated unstaged if a problem develops with the tertiary air port system.

The staged tests covered a range of operating conditions and burner settings. At the optimum burner settings, the flame was stable over a wide range of burner zone stoichiometries from unstaged conditions down to 64 percent theoretical air. As the burner zone stoichiometry was decreased, the flame length increased from 3 m (13 ft.) for unstaged conditions to about 6 m (19 ft.) at the design point.

The NO and CO emissions at full load with the Indiana coal are shown in Figure 7. These results are similar to those obtained with the development DMBs and the original prototype burner. For fixed overall stoichiometry, NO emissions decrease approximately linearly as the burner zone stoichiometry decreased. Thus it is desirable to operate at the lowest burner zone stoichiometry where the flame stability and combustion efficiency are acceptable. As burner zone stoichiometry decreased, CO emissions remained constant initially and then increased. Further decreases in burner zone stoichiometry resulted in a flame stability limit of about 64 percent theoretical air. At the design point burner zone stoichiometry (70 percent theoretical air) NO_x emissions were 200 ppm, which corresponds to 95 ng/J (0.22 lb/10⁶ Btu), and CO emissions were about 70 ppm which is in the range of typical commercial burners, less than 100 ppm.

Other measurements at the design point are summarized below:

- Particulate carbon content was 4.4 percent indicating a carbon utilization efficiency of 99.2 percent.
- Hydrocarbon emissions were lower than the detectability limit (1.0 ppm) in two tests.
- N₂O emissions were 39 and 42 ppm in two tests.

Burner performance was evaluated over ranges of excess air and firing rate. Flame characteristics and CO emissions were essentially constant down to an excess air level of about 15 percent. However, NO_x emissions were sensitive to excess air increasing at about 15 ppm/% excess air. Flame stability was acceptable with the optimum burner settings and design point burner zone and overall stoichiometries, from full load to about 67 percent of full load. Increasing the excess air to 32 percent allowed stable operation down to 50 percent of full load. NO_x emissions decreased slightly as load was reduced at constant excess air and increased as excess air was increased at low load.

One key aspect of the prototype burner tests was to verify that all aspects of the burner performance meet the host boiler requirements. Table 3 compares the requirements of the WIPCO unit with the performance of the final prototype burner design in the LWS. All requirements were met.

DMB FIELD INSTALLATION

The WIPCO host boiler has been retrofitted with DMBs. The DMBs are based on the design of the final prototype burner tested in the LWS. The registers, coal nozzle and burner exit are identical except that the materials of construction, fasteners, etc., for the WIPCO DMBs have been upgraded to Foster Wheeler commercial standards for field operating equipment. The tertiary air port array installed at WIPCO is designed to match the tertiary air velocity used in the prototype tests. However, due to the multi-burner configuration and structural constraints the number and location of ports are considerably different.

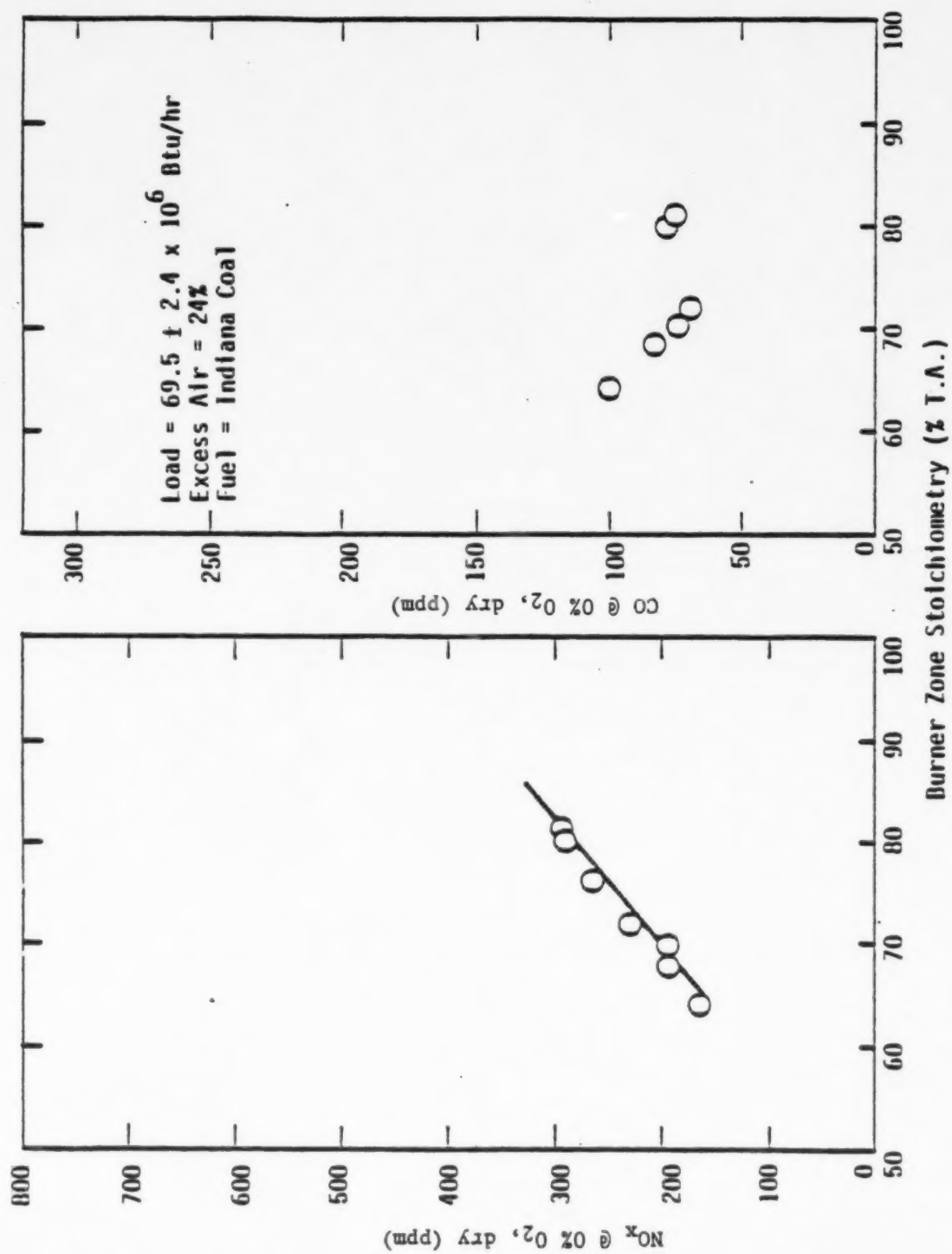


Figure 7. Performance of final prototype DMB with optimum settings in the new LWS.

TABLE 3. PROTOTYPE BURNER PERFORMANCE SUMMARY

PARAMETER	REQUIREMENT	DEMONSTRATED PERFORMANCE
Flame Shape	Compatible with host furnace	Flame length: 5.8 m (19 ft)
Flame Stability	Stable over host load range; Insensitive to burner settings.	Minimum load less than 50% at full-load
Ignition	Compatible with commercial system	Confirmed
Flame Scanning	Compatible with commercial system	Confirmed
Pressure Drop	Less than/equal to host burner	Confirmed
Efficiency	Equal to/better than host burner	Confirmed
Tertiary Ports	Locations compatible with host furnace	CO = 70 ppm, Carbon in ash = 4.4 % } Ports redesigned for field evaluation
Control System	Compatible with commercial standards	
NO _x	Program goal: 87 ng/J (0.2 lb/10 ⁶ Btu)	95 ng/J (0.22 lb/10 ⁶ Btu) at design point. Sensitive to excess air and burner zone stoichiometry. Insensitive to load.

It was originally planned to install an array of nine tertiary air ports in three rows of three ports each above, between and below the burners. However, applying this array to the WIPCO unit would have caused the following structural problems:

- Interference with buckstays.
- Interference with windbox trusses.
- Interference with pulverizer air supply ducts.
- Elimination of hopper support tubes.

The WIPCO unit is designed with buckstays between, above and below the burners. Installation of the ports would interfere with all three. The windbox front-face and the outboard portions of the burner are supported by several trusses in the windbox. The ports and control mechanisms interfere with several trusses. The two bottom corner ports are directly over the pulverizer supply ducts. Control systems for the ports would interfere with air flow to the pulverizers. Finally, the additional tube bends required for the ports affect almost all of the remaining straight tubes which normally support the hopper.

After considerable analysis and discussion by EER, EPA and Foster Wheeler, the compromise port arrangement shown in Figure 8 was selected. Thirteen (13) tertiary air ports were installed: four above the burners, four below the burners, four outboard of the burners and one in the center of the burner array. This arrangement distributes the tertiary air around and between the burners while minimizing structural problems. The ports above the burners are the maximum size that will clear the buckstay. The port in the center is reduced in diameter to allow clearance for its control mechanism between the burner registers. The ports along the sides have been moved to allow free flow into the pulverizer ducts. The bottom of the windbox has been lowered to provide a plenum for installation of the lower ports.

The structural problems which could not be eliminated are as follows:

- Front-Wall Replacement. Due to the large number of complex tube bends, the entire front wall had to be replaced.
- Buckstay Removal. The buckstay between the burners had to be removed, and additional windbox structures were constructed to handle the pressure loads.
- External Hopper Support. The front wall strength was inadequate to support the hopper due to the large number of bends. An external hopper support was constructed to handle the hopper weight.

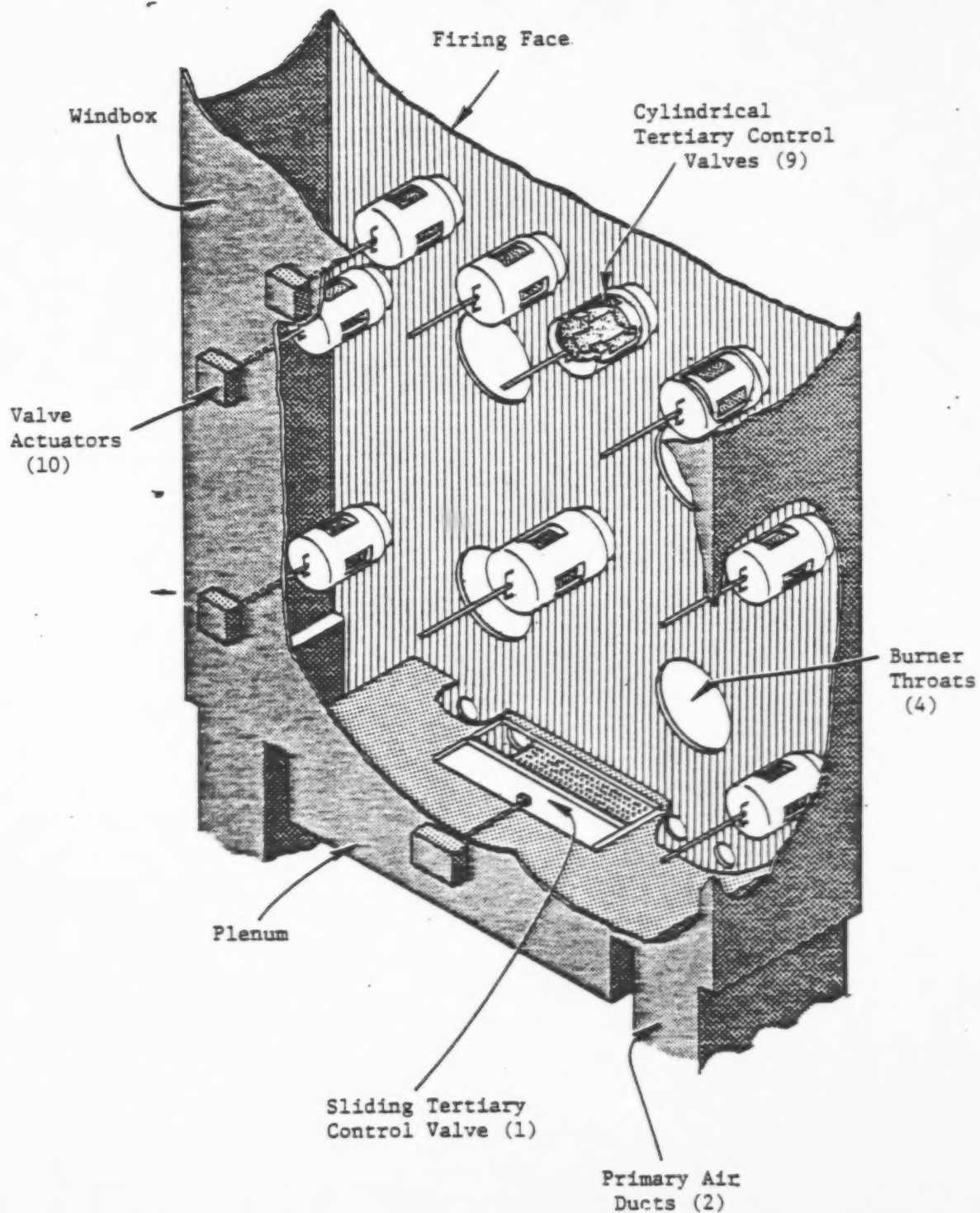


Figure 8. Tertiary air ports for WIPCO DMBs.

The tertiary air ports and burners are supplied with combustion air from a common windbox. The air distribution to the burner passages is controlled and measured with separate control systems. The control systems on the burners were discussed in the third section. All tertiary air ports except the bottom row are equipped with cylindrical control valves. Each valve has two parts: a stationary inner cylinder with four perforated plates in the circumference and a rotating outer cylinder with slots matching the perforated plate locations. Rotating the outer cylinder changes the alignment between the slots and perforated plates and this varies the effective open area and the flow rate through the valve. The flow rate is correlated with the pressure drop across the valve and valve position. The bottom four ports are supplied with air from a separate plenum. The air flow rate into the plenum is controlled by a sliding plate which varies the open area of a stationary perforated plate. Air flow rate is correlated with pressure drop between the windbox and plenum and valve position.

The original equipment burner control system at WIPCO included the following components:

- Oil-fired ignition system.
- Flame scanners.
- Manual register drives.

This system was installed in 1965 and is not representative of modern burner control systems. It was inadequate to control the DMBs and the tertiary air ports. A new control system was installed with electric drives on the registers and on the tertiary air ports.

In summary, the DMB installation at WIPCO required some compromises in burner design and modifications to the furnace and windbox structures. Start-up of the new burners has been successfully completed, and the burners are now operating over the normal duty-cycle with the tertiary air ports closed. Low NO_x optimization tests with the tertiary ports open will begin shortly.

ACKNOWLEDGMENT

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NO_x EMISSIONS CONTROL WITH THE DISTRIBUTED MIXING BURNER

Part II. Thermal Environment and Heat Release Capacity Scaling

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ABSTRACT

Field operating industrial and utility furnaces have a wide range of thermal environments and utilize burners with a wide range of heat release capacities. Both of these factors can affect burner performance and in particular NO_x emissions. This part discusses tests of several DMBs in three research furnaces. The tests covered a wide range of burner scales and thermal environments. Implications for applications to field operating equipment are discussed.

INTRODUCTION

The field evaluation of the DMB discussed in Part I of this paper will provide data on the performance of a 20 MW (69×10^6 Btu/hr) DMB in a single wall-fired furnace firing a high volatile bituminous coal with a steam raising capacity of 98×10^3 kg/hr (215×10^3 lb/hr). To evaluate the potential performance of the DMB in the full range of the existing and projected inventory of industrial and utility boilers, the effects of burner capacity, furnace confinement and fuel composition must be considered. As part of the DMB development under EPA Contracts 68-02-1488 and 68-02-3127, and continuing work under EPA Contract 68-02-2667, seven burner configurations were fired in five research furnaces. Part II of this paper compares the results of these tests to evaluate burner scale and furnace confinement effects.

The data base is shown in Table 1. Comparison 1 involves three scales of development DMBs fired in one furnace and one scale of a similar burner design fired in a second furnace. Comparison 2 involves the initial prototype DMB fired in two furnaces, and comparison 3 involves the final prototype DMB fired in two furnaces. Comparison 4 involves the versatile DMB (being developed under EPA contract 68-02-2667) fired in a research furnace with variable heat extraction. The following section presents the designs of the burners and research furnaces and the next section discusses the test results and comparisons. The last section summarizes the results and presents conclusions relative to burner scale and furnace confinement effects.

EQUIPMENT

Burners

The following burner designs were tested:

TABLE 1. DATA BASE

COMPARISON NUMBER	BURNER	CAPACITY 10^6 Btu/hr	FURNACE
1	Single Secondary Development DMBs	100	Old LWS
		50	
		4 x 12.5	
		12.5	Old SWS
2	Initial Prototype DMB	70	Old LWS New LWS
3	Final Prototype DMB	70	New LWS MT
4	Versatile Burner	10	New SWS

Note: 10^6 Btu/hr = 0.29 MW

- Single Secondary Development DMBs - 3.7, 14.6 and 29.3 MW (12.5, 50 and 100 x 10⁶ Btu/hr)
- Initial Prototype DMB - 20.4 MW (70 x 10⁶ Btu/hr)
- Final Prototype DMB - 20.4 MW (70 x 10⁶ Btu/hr)
- Versatile DMB - 3.7 MW (12.5 x 10⁶ Btu/hr)

The design of the Single Secondary Development DMBs is illustrated in Figure 1A. They have central coal nozzles and single concentric secondary air passages with swirl vanes. This burner design was constructed in three scales using constant velocity and geometric scaling. The 3.7 MW (12.5 x 10⁶ Btu/hr) scale was chosen so that a 2 x 2 array of burners could be tested in place of a single 14.6 MW (50 x 10⁶ Btu/hr) burner to provide an evaluation of burner scale independent of furnace confinement effects. These burners were research designs and did not incorporate commercial burner components.

The prototype DMBs were designed by integrating the DMB design criteria (the parameters which resulted in optimum performance with the development DMBs), Foster Wheeler burner components and the requirements of the WIPCO host boiler. The initial prototype DMB was designed by modifying the exit geometry specified by the design criteria to meet WIPCO windbox depth limitations. The final prototype DMB incorporated Foster Wheeler Controlled Flow Burner exit geometry. Both prototype DMBs have annular coal nozzles and dual secondary air passages with registers for swirl control. Other details of the prototype burner design were discussed in Part I.

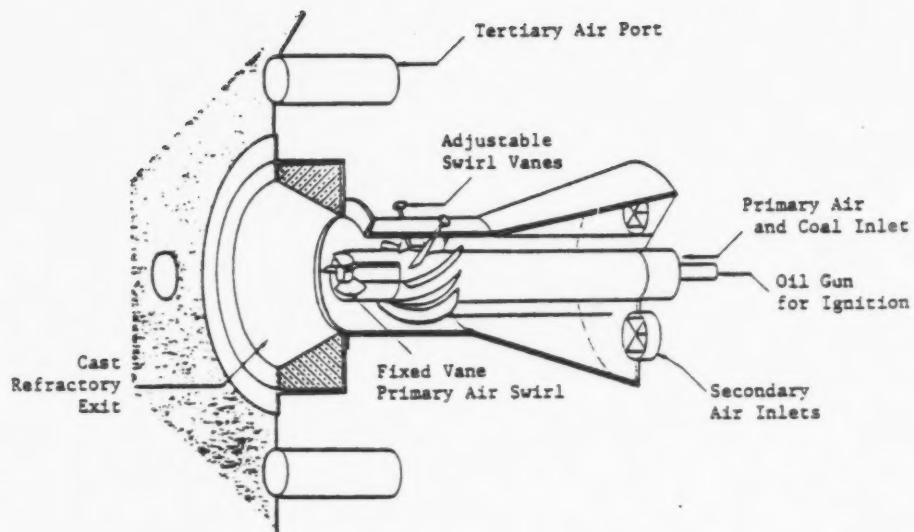
The Versatile DMB is shown in Figure 1B. This research burner is being used to evaluate the effects of burner parameters on overall burner performance under EPA contract 68-02-2667. It has a central coal nozzle with an impeller/spreader. Secondary air is supplied through two annular passages with registers for flow rate control.

Research Furnaces

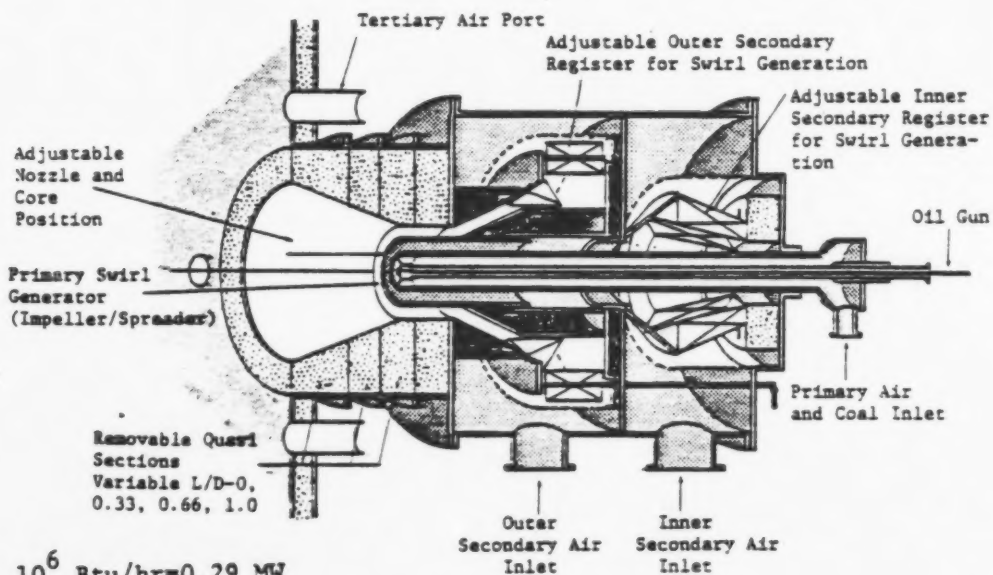
The DMBs were tested in the following research furnaces:

- Old Small Watertube Simulator (old SWS).
- New Small Watertube Simulator (new SWS).
- Old Large Watertube Simulator (old LWS).
- New Large Watertube Simulator (new LWS).
- Medium Tunnel (MT).

The designs of these furnaces are shown in Figure 2, and Table 2 compares the design and operating parameters.



A. Development DMBs ($12.5, 50$ and 100×10^6 Btu/hr).



Note: 10^6 Btu/hr = 0.29 MW

B. Versatile burner (12.5×10^6 Btu/hr capacity).

Figure 1. Research DMBs.

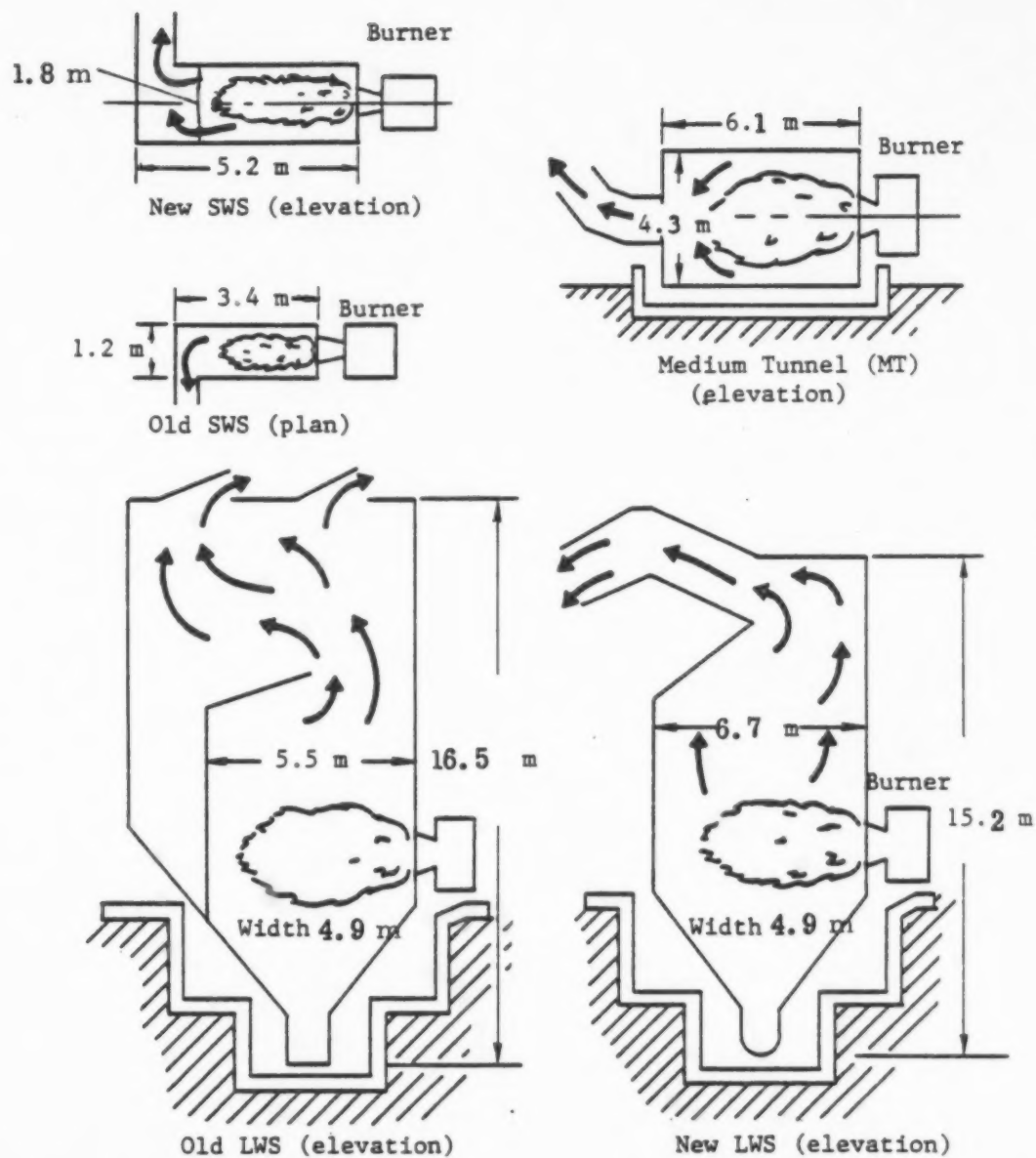


Figure 2. Research furnaces.

TABLE 2. RESEARCH FURNACE CHARACTERISTICS

FURNACE	OLD SWS	NEW SWS	OLD LWS	NEW LWS	MT
Shape	Rectangular	Horizontal cylinder	Rectangular with hopper and nose	Rectangular with hopper and nose	Horizontal cylinder
Firing Configuration	End	End	Front wall	Front wall	End
Exhaust	Side-rear	Top-rear	Top	Top	End
Firing Capacity (Btu/hr)	15×10^6	15×10^6	125×10^6	150×10^6	80×10^6
Width (ft)	4	6 (dia)	16	16	14 (dia)
Firing Depth (ft)	11	17	18	22	20
Overall Height (ft)	5	-	54	50	-
Cooling	External water spray	External water spray	External water spray	External water spray	External water spray
Refractory Insulation in Burner Zone	Bottom	50% of circumference and 100% of target wall	None	Side walls (from knuckle up 16 ft)	50% of circumference and 100% of target wall
Heat Release/Cooled Surface* (Btu/hr ft ²) at:	66,000	50,000	50,000	100,000	90,000
Burner Firing Rate (10 ⁶ Btu/hr)	12.5	12.5	70	70	50

Note: 10^6 Btu/hr = 0.29 MW
1.0 ft = 0.30 m

* Definition in text

The old SWS was the original small research furnace used for DMB development tests. It was rectangular in cross-section with the burner mounted in one end and the exhaust exiting the other end. All surfaces were water-cooled except for the floor which was insulated with refractory.

The new SWS was designed to replace the old SWS. It is a horizontal cylinder slightly larger than the SWS. The burner is mounted on one end and the exhaust exits the other end. The furnace walls are partially insulated with refractory: axial strips of refractory on the circumference and a full covering of refractory on the rear wall. The new SWS has been fired with the Versatile burner.

The old LWS is the original large research furnace used for the development DMB tests at 14.6 to 29.3 MW (50 to 100 x 10⁶ Btu/hr). The shape was similar to a small front-wall-fired boiler with a hopper bottom and nose above the firing zone. All furnace walls were water-cooled with no refractory insulation. The old LWS was used for the development DMBs and the initial prototype DMB tests.

The new LWS was designed to replace the old LWS. The geometry is similar but the furnace sidewalls are insulated with refractory. The initial and final prototype burners were tested in the new LWS.

The MT is a horizontal tunnel furnace similar to the new SWS in construction but considerably larger. It was used to test the initial and final prototype burners.

These five furnaces provide a range of geometries and also a range of thermal environments. One index of the thermal environment is the heat release per cooled surface area in the flame zone (Q/A). Furnaces with high Q/A have low heat extraction and hence higher effective flame temperatures. Table 2 lists Q/A for the research furnaces at the firing rates used for a majority of the tests. For the old and new SWS and MT, the cooled surface area was the furnace surface area not covered with refractory. For the old and new LWS, which have a structure similar to a boiler, the cooled surface area was the plan area above and below the burner zone and the sidewall area from the knuckle to 3 m (10 ft.) above the burner centerline. (This is the same surface area used in Foster Wheeler's Burner Zone Liberation Rate calculation.) It should be noted that Q/A is an approximate indication of heat extraction. Other parameters such as furnace shape and flow characteristics would also be expected to influence heat extraction.

RESULTS

Comparison 1 - Development DMBs in Old SWS and LWS. Three configurations of Single Secondary Development DMBs were tested in the old LWS: 14.6 and 29.3 MW (50 and 100 x 10⁶ Btu/hr) burners were tested individually and 4-3.7 MW (12.5 x 10⁶ Btu/hr) burners were tested as a 2 x 2 array. In addition, a single 3.7 MW burner was tested in the old SWS. These burners were designed to have the same velocities through the burner passages at full load with similar geometry. Each burner/furnace configuration was tested over a wide range of test conditions. Data obtained at the same conditions (except for

firing rate) are shown in Figure 3. These data provide an evaluation of the burner scaling method, furnace confinement and flame interaction. Figure 3A shows NO_x emissions as a function of total heat release. Within some scatter, the data from the LWS tests lie along a single line. This suggests that NO_x emissions are related to total heat release and that the effects of burner scale and flame-to-flame interactions are small. The SWS data shown in Figure 3A do not agree with the LWS data. However, as was shown in Table 2, the SWS has a high value of Q/A . These same data are replotted as a function of Q/A in Figure 3B. The LWS and SWS data now appear to be very similar. This suggests that, for this burner design, the primary parameter influencing NO_x emissions is furnace confinement.

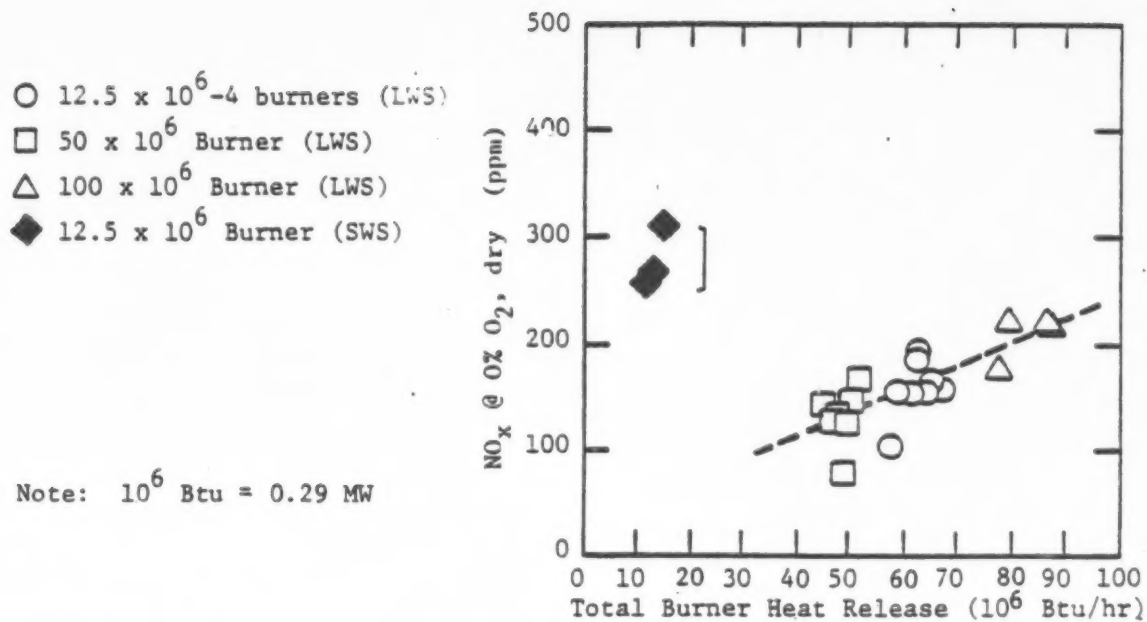
Comparison 2 - Initial Prototype DMB in Old and New LWS. Comparison 1 showed that for constant velocity scaling, the NO_x emissions from DMBs were related primarily to furnace confinement. However, it is important to note that the primary variable was the burner firing rate, not the furnace design. Comparison 2 involves tests of one burner, the initial prototype DMB, in two research furnaces, the old and new LWS. As shown in Table 2, the old and new LWS are geometrically similar. The primary difference is the refractory insulation in the new LWS which increases the Q/A by a factor of two.

Figure 4 compares the NO_x and CO emissions for the initial prototype DMB in the old and new LWS. The CO emissions in the new LWS are considerably lower than in the old LWS. This indicates that the refractory insulation in the new LWS provides a hotter thermal environment resulting in improved combustion efficiency. However, NO_x emissions are essentially unchanged. This suggests that, for the initial prototype DMB, NO_x emissions are independent of thermal environment over the range investigated.

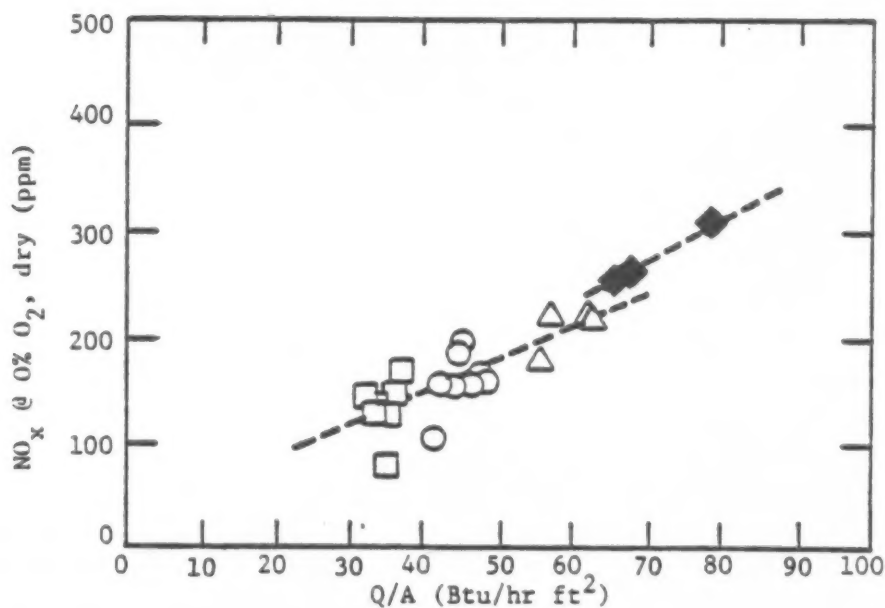
Comparison 3 - Final Prototype DMB in the New LWS and MT. The final prototype DMB design was fired in the new LWS and the MT. In the MT, the firing rate was limited to about 70 percent of capacity due to flame impingement. The flame filled the MT and extended part way into the exhaust duct. The Q/A for the LWS tests was approximately the same as for the MT tests. However, the net heat extraction was greater in the LWS. Furnace exit temperatures were up to 280°C (500°F) lower in the LWS.

NO_x and CO emissions are shown in Figure 5. In the MT, NO_x emissions are higher and CO emissions are lower than in the LWS. These differences are due to a combination of furnace confinement and thermal environment effects. The smaller size of the MT narrowed and elongated the flame and thus may have altered the mixing of the tertiary air. Since the basis of the low NO_x emissions of the DMB is delayed mixing of the tertiary air, this may have affected NO_x emissions.

Comparison 4 - Versatile Burner in the New SWS. The Versatile burner was tested in the new SWS with variable refractory insulation. In one test the refractory insulation consisted of insulation on the front and rear walls as well as 50 percent of the cylinder surface. In another test, a combination



A. Effect of total burner heat release.



B. Effect of furnace Q/A.

Figure 3. Comparison 1 single-secondary development DMBs in old LWS and SWS.

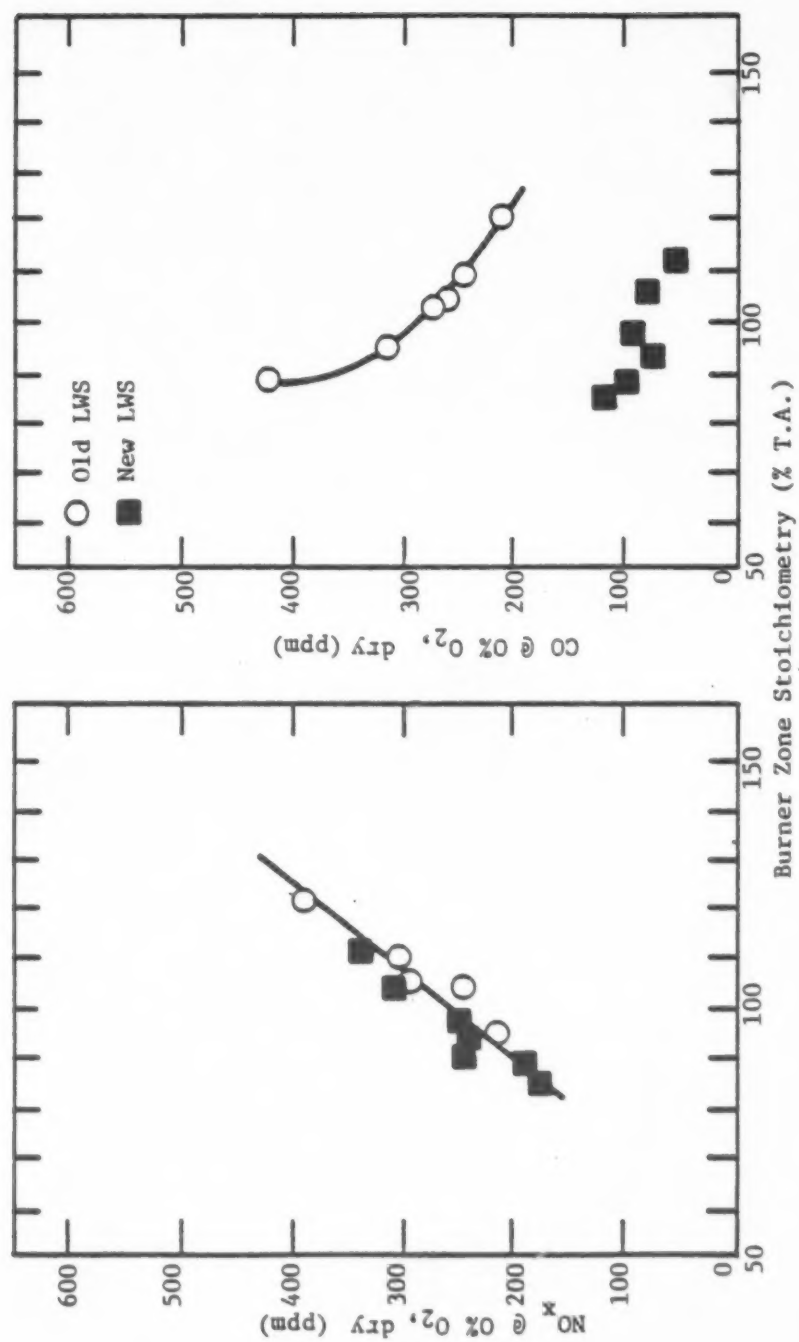


Figure 4. Comparison 2 initial prototype DMB in old and new LWS.

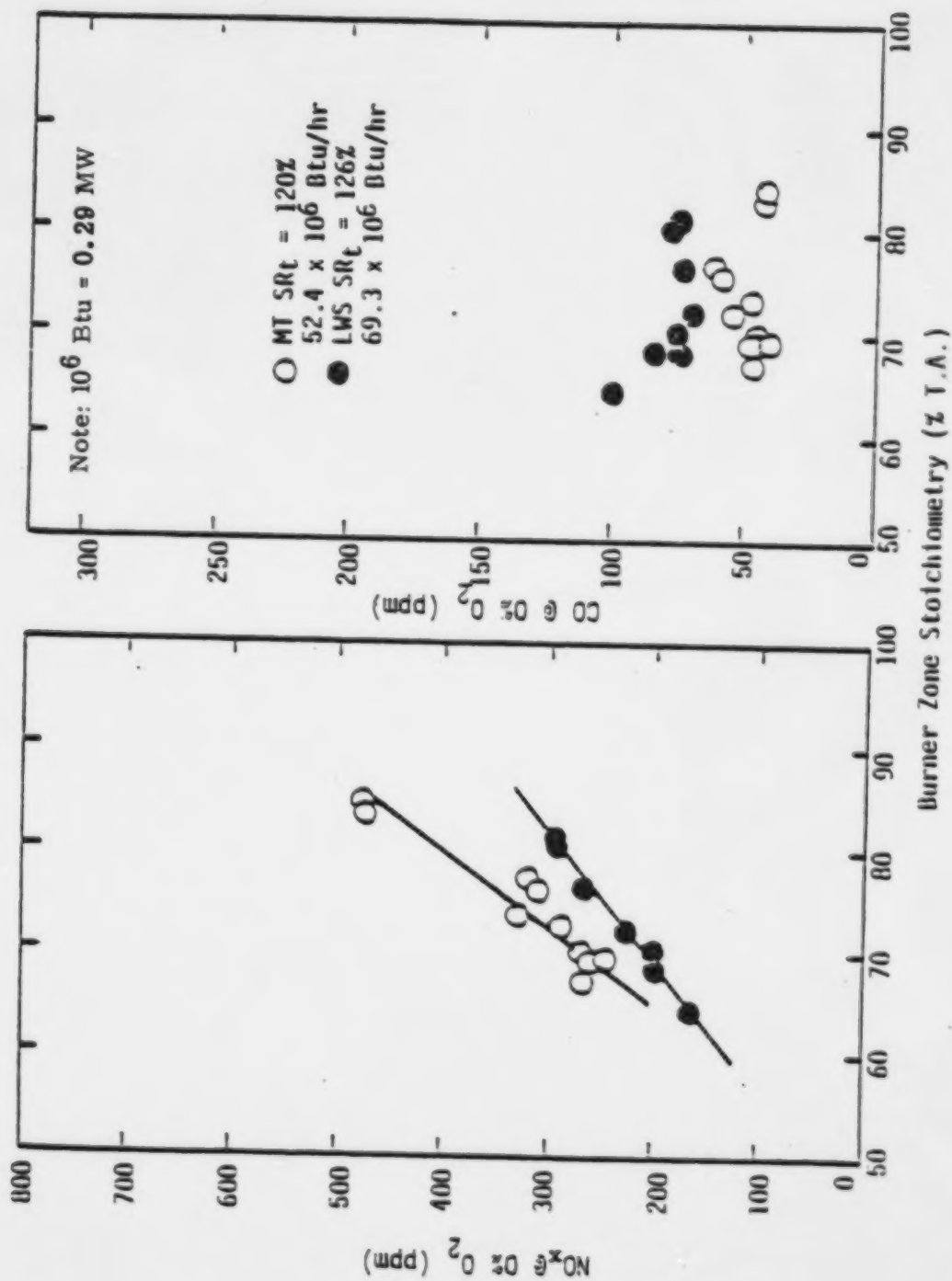


Figure 5. Comparison 3 - final prototype DMB in new LWS and MT.

of fire-brick and fiber insulation was used to insulate an additional 40 percent of the cylinder area. The test results are compared in Figure 6. The hotter thermal environment had a negligible effect on flame shape but increased NO_x emissions under unstaged conditions (high burner zone stoichiometry). NO_x emissions were unaffected at low burner zone stoichiometry where the DMB is normally operated.

CONCLUSIONS

The conclusions reached by evaluating the four comparisons are shown in Table 3. Comparison 1 showed that increasing burner capacity in a fixed furnace design resulted in increased NO_x emissions. There was no measurable effect of the flame-to-flame interaction produced in the 2 x 2 array. NO_x emissions were approximately proportional to furnace Q/A. In comparison 2, increasing the insulation in the furnace with a fixed burner design had no effect on NO_x emissions. In comparison 3, one burner was tested in two furnaces with similar Q/A but differing furnace volumes. NO_x emissions were higher in the compact furnace. In comparison 4, increasing the insulation in the furnace had no effect on NO_x emissions at DMB operating conditions but a significant increase resulted under unstaged operating conditions.

In interpreting these results it is important to recognize that the Q/A parameter is an approximate index of heat extraction, and comparisons are valid for fixed geometry only. This was illustrated by comparison 3 where heat extraction was greater in one furnace although the Q/A values for both furnaces were comparable. It is also important to recognize that the range of burner capacity, furnace confinement and number of burners evaluated here does not include the full range of field operating steam generators. Many field operating systems utilize a large number of burners with greater capacity than those tested here in furnaces with lower heat extraction. Thus it is difficult to extrapolate these test results to the full range of field operating systems.

The evaluation of scaling and thermal environment effects is continuing. Under EPA contract 68-02-2667, additional tests of the Versatile DMB will be conducted in the new SWS and MT. Under EPA contract 68-02-3130 several DMBs and commercial burners will be tested in the LWS. Thermal insulation will be added to match the conditions in two field operating systems firing commercial burners. The results of these tests will considerably extend the range of application of the DMB.

ACKNOWLEDGMENT

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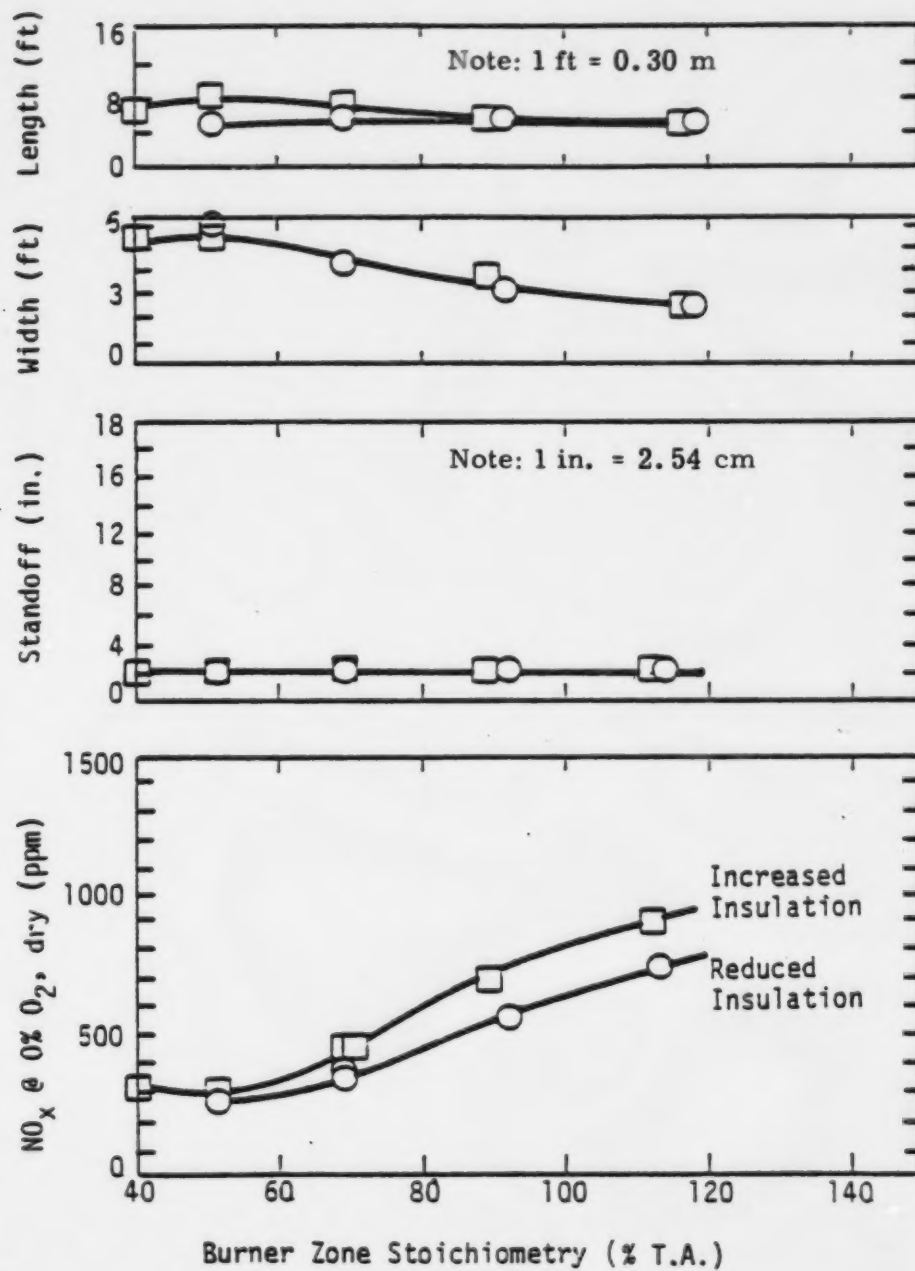


Figure 6. Comparison 4 Versatile DMB in new SWS.

TABLE 3. CONCLUSIONS FROM DATA COMPARISONS

COMPARISON	PRINCIPAL VARIABLE	EFFECT ON NO _x EMISSIONS
1. Development DMBs in old LWS and SWS	Burner capacity	Increase with furnace Q/A flame interactions insignificant
2. Initial prototype DMB in old and new LWS	Furnace insulation	No effect of Q/A
3. Final prototype DMB in new LWS and HT	Furnace confinement	Increase in smaller furnace
4. Versatile DMB in new SWS	Furnace insulation	No effect at DMB conditions, increase at unstaged conditions

EVALUATION OF TANGENTIAL
FIRED LOW NO_x BURNER

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ABSTRACT

Mitsubishi Heavy Industries (MHI) was contracted by the Electric Power Research Institute (EPRI) and the Electric Power Development Corporation (EPDC) to evaluate and to confirm the advanced low-NOx burner technology to minimize NOx emissions from tangential fired pulverized coal boilers in United States.

The advanced low-NOx burner technology used, named low-NOx PM burner technology, has been developed by MHI in response to stringent NOx emission regulations in Japan.

The four coals selected for the low-NOx PM combustion test provide a wide range in coal properties which are typical of U.S. utility usage. The coals include (1) low sulfur Eastern bituminous coal, (2) high sulfur Mid-western bituminous coal, (3) high nitrogen, low sulfur Western sub-bituminous coal and (4) Texas lignite.

From the combustion tests of the low-NOx PM burner using the 4 ton/hour (nominally 12.5 MW) pulverized coal fired test furnace with the U.S. typical four coals, the excellent low NOx performance was proved with stable and good combustion condition (low unburnt carbon). And, the applicability of the low-NOx PM burner for tangential-fired pulverized coal utility boilers was confirmed.

INTRODUCTION

Oxide of nitrogen (NOx) is one of the harmful air polluting substances generated from boilers. Moreover, by the recent research it is becoming clear that NOx is a major contributor in the much publicized acid rain problems.

As a means of reducing NOx emissions by combustion modification from oil and/or gas fired boilers, MHI has already developed the low-NOx burner technology named PM burner technology (1), (2), (3) and the low-NOx combustion technique named MACT method (4), (5) for practical application.

In case of tangential-fired pulverized coal boiler MHI has also developed a low-NOx coal burner named SGR burner and PM burner (6), (7), the former has been applied to two 500 MW tangential-fired pulverized coal utility boilers already in commercial operation and the latter is now being applied to a 250 T/H industrial boiler now under construction and new utility boilers under design.

This paper shows the results of the experimental evaluation of the four U.S. coals, which were typical of U.S. utility usage, with the low-NOx PM burner technology in the MHI's 4 ton/hour combustion test furnace maintaining combustion conditions compatible with full-scale utility boiler and operating practice.

TANGENTIAL-FIRED LOW-NO_x PM BURNER

MHI started a research program at around 1975 to develop a low NO_x pulverized coal burner for tangential-fired utility boilers. Since coal contains organic nitrogen about 10 times as great as that in oil and gas, most of the NO_x generated from combustion of coal is fuel NO_x. This is an important point to keep in mind when studying NO_x reduction particularly for the pulverized coal fired units.

By the basic tests to clarify the NO_x production characteristics of the pulverized coal flame using reactor tubes and by a series of prototype low NO_x burner combustion tests to find the optimum burner nozzle configurations using 4 ton/hour MHI combustion test furnace, MHI developed the coal fired low-NO_x PM burner as one of the most reliable means to reduce NO_x productions for tangential-fired utility boilers (6).

NO_x Production Characteristics on Pulverized Coal Combustion

To understand the low NO_x PM technology, basic information on the NO_x production characteristics of pulverized coal (6) is introduced as follows. This information is obtained by use of two reactor tubes, the first is mainly for the volatile matter combustion zone and the second is mainly for the char combustion zone. And these two reactor tubes are composed of vertically connected two cylindrical electric furnaces, and inside them are located ceramic reactor tubes 24 mm in diameter and 1000 mm in length connected end to end with a silica joint.

Fig. 1-1 shows the relation between NO_x formation and gas temperature at an air ratio 0.41 in the primary reactor. Hollow circles and squares in the figure show N₂-base NO_x values and solid circles and squares show Ar-base values, and the differences between them represent thermal NO_x values. It can be seen from Fig. 1-1 that the majority of the total NO_x is fuel NO_x at a temperature range below 1400 °C and that 25 to 30 percent of the total NO_x is the thermal NO_x at 1600 °C. Thermal NO_x values calculated by Zeldvich's formula are also shown in Fig. 1-1.

From Figs. 1-2, 1-3, and 1-4, it is observed that combustibles should stay in the volatile matter combustion zone as long as possible at a temperature as high as practicable and the combustion process should be completed in the char combustion zone held at a properly low temperature in order to accomplish low NO_x combustion of pulverized coal.

Fig. 1-5 shows the relation between the NO_x formation and the air ratio in the primary reactor. The NO_x value decreases as the air ratio in the primary reactor decreases when the air ratio is in the range from 2.0 to 0.6 and increases as the air ratio decreases when it is in the range from 0.6 to 0.3, but the NO_x value decreases again as the air ratio decreases when it is in the range of 0.3 and below.

The results of the basic tests using reactor tubes indicate that it is necessary to satisfy the following conditions in order to accomplish low NO_x combustion.

- 1) The temperature of the volatile matter combustion zone should be kept as high as possible and the combustibles should stay in this zone as long as practicable.
- 2) The temperature of the char combustion zone should be properly low and the combustion of the combustibles should be completed in this zone.

And, moreover

- 3) the results of the basic tests with reactor tubes indicate that the NO_x value greatly varies with the air ratio in the primary reactor as shown in Fig. 1-5.

The writers advanced their study with an emphasis was on this point. The NO_x formation characteristic of the prototype low-NO_x burner in combustion test furnace that burns coal in a flame pattern divided into a primary and a secondary combustion zone as explained later was investigated varying primary air/coal ratio in the primary combustion zone and the results showed qualitatively coincidence with that of the basic tests, as shown in Fig. 1-5.

NO_x Formation Characteristics of Pulverized Coal Flame

The combustion zone of pulverized coal can be divided into two sub-combustion zones, the primary and the secondary combustion zone as shown in Fig. 2-1 and the NO_x value in each zone should be considered as shown in Fig. 2-2 judging from the results of the basic tests (6), (7).

In Fig. 2-2 the sum of [NO_x]_p from the primary combustion zone and [NO_x]_s from the secondary combustion zone is the total NO_x generated from the combustion of pulverized coal. As shown in Fig. 2-2 (iii), NO_x increases in the region where the primary air/coal ratio is between 0 and 3 to 4 and decreases in the region where this ratio is between 3 to 4 and 7 to 8 and again increases when this ratio exceeds 7 to 8 as the primary air/coal ratio increases in the respective regions.

This trend of NO_x formation shows a qualitatively excellent coincidence with the result of the basic tests made using reactor tubes as shown in Fig. 1-5.

Concept of Low-NO_x PM Burner

With the coal fired low-NO_x burner, the NO_x value falls as the primary air/coal ratio deviates from the region where this ratio is 3 to 4 (kg/kg coal) that corresponds to the theoretical air for volatile matter in either direction increasing or decreasing.

Therefore, if the air/coal mixture supplied to a burner with the primary air/coal ratio C_0 (2 to 3 (kg/kg coal) for ordinary mills) is divided into two streams of different ratios, C_1 for coal-rich Conc nozzle and C_2 for coal-lean Weak nozzle, to burn separately as shown in Fig. 2-3, the NO_x value $((\text{NO}_x)\text{PM})$ for the whole burner will be the weighted mean of $(\text{NO}_x)C_1$ and $(\text{NO}_x)C_2$ and will become obviously lower than $(\text{NO}_x)C_0$ that is the NO_x value obtainable in case the whole air/coal mixture with ratio C_0 burns undivided.

If coal is burned in Conc flame with coal-rich ratio C_1 or Weak flame with coal-lean ratio C_2 only, NO_x value will be sufficiently low as shown in Fig. 2-3, but the combustion is undesirable.

The combustion with Conc flame only will cause a high percentage of unburned carbon in fly ash though the combustion itself is stable. The combustion with Weak flame only can essentially maintain low unburned carbon in fly ash due to high oxygen concentration, however, the effect is deteriorated due to poor ignition stability. Thus, only the combined use of Conc flame and Weak flame can accomplish the low NO_x combustion with stable ignition and reduced unburned carbon in fly ash.

Structure of Low- NO_x PM Burner

Fig. 2-4 shows the structure of a coal fired low- NO_x PM burner. The Conc (or concentrated fuel) nozzle located at the middle of the burner is provided with a flame holder at its outlet to stabilize the ignition of the rich coal/air mixture injected from the nozzle. SGR (or separating gas recirculation) nozzles are arranged above and below the Conc nozzle, one at each part. An auxiliary air nozzle and an oil nozzle are located below the lower SGR nozzle and a Weak (or fuel-lean) nozzle for lean coal/air mixture, and an auxiliary air nozzle and an oil nozzle are located above the upper SGR nozzle. The upper SGR nozzle is to retard the diffusion of secondary air from the upper auxiliary air nozzle to the Conc flame and the lower SGR nozzle is to retard the mixing of the Weak flame from the Weak nozzle with the Conc flame.

Fig. 2-4 also shows a coal feed line incorporated with a separator. The separator divides the coal/air mixture in the line into two streams of different coal/air ratios and supplies rich coal/air mixture to the Conc nozzle and lean coal/air mixture to the Weak nozzle.

The capacity of the coal fired low- NO_x PM burner to be used was designed with three tons per hour at full load.

ANALYSIS OF U.S. COALS TESTED

The four U.S. coals selected for the low NO_x PM combustion tests provide a wide range in coal properties which are typical of large segments of U.S. utility usage. The results of analyses of the four coals are shown in Table 1. Main features of these coals are as follows.

- (1) The Texas lignite, which is characterized by high moisture content, low ash fusion temperature, high oxygen content and low fixed carbon to volatile matter ratio.
- (2) The Western subbituminous coal from Montana, which is characterized by low sulfur content, high nitrogen content, extremely high sodium (Na) content and low ash fusion temperature.
- (3) The Midwestern bituminous coal from Illinois, which is characterized by high sulfur content, low ash fusion temperature, extremely high iron (Fe) content and medium fixed carbon to volatile matter ratio.
- (4) The Eastern bituminous coal from East Kentucky, which is characterized by low sulfur content, low ash content, high ash fusion temperature and high fixed carbon to volatile matter ratio.

FACILITIES FOR COMBUSTION TESTS

Combustion Test Equipment

Fig. 3 shows a flow sheet of the 4 ton/hour (nominally 12.5 MW) test furnace and Table 2 shows main particulars of the test equipment.

The body of the furnace is a sea water cooled double walled cylinder of 4.4 m in inside diameter and 20 m in length. A part of its inner surface is lined with refractory to keep the furnace temperature at around the level of the actual boiler furnace so that the state of self-ignition of injected coal, degree of NO_x formation and the percent of unburned carbon in fly ash in the actual boiler can be simulated.

Combustion air is supplied by a forced draft fan to the burner after being heated to about 300 °C by air preheater as is usually the case with actual boilers. A part of the air is directly injected into the furnace as overfire air (OFA) from the OFA ports located on the furnace wall downstream from the burner. Another part of the air is used coal carrying primary air. It is branched off and mixed with cold air to a proper temperature and is led to below the pulverized coal bin (PC bin) and passes to the burner carrying pulverized coal fed through the coal feeder.

The combustion gas leaving the furnace is cooled by the gas cooler and passes through the cyclone separator separating fly ash and then enters the air preheater. After heating air in the air preheater, the gas leaves it at about 150 °C to the bag filter where it further separates remaining fly ash and then it is discharged to the atmosphere from the stack.

A part of the flue gas is recirculated by the gas recirculation fan (GRF) and injected into the furnace partly through the SGR nozzles of the burner and/or partly mixed with secondary air (GM).

Though not shown in the flow chart, a heavy oil line and a light oil line are also provided to the test furnace, the former is for the start-up burner and the latter is for the ignitor.

Moreover, though not shown in the flow chart, a 2.8 ton/hour bowl mill is also provided near the test furnace to supply the pulverized coal into PC bin.

Measuring Instruments

Measuring items, measuring instruments and measuring method used are shown in Table 3. Flue gas is sampled for analysis from the straight cylinder test section at the outlet of the test furnace. Fly ash is sampled from one of the cells of the multi-cyclone separator and bag filter separately. After measuring the amount of unburned carbon in each sample, the weighted mean is calculated by the quantities of ash separately collected.

As informative data, flame temperature is measured with an optical pyrometer and heat flux to the furnace wall is measured with heat flow meters.

TEST METHOD

The three coals other than Lignite was dried and pulverized by 2.8 ton/hour bowl mill using preheated air and stored in pulverized coal bin. The Lignite was dried and pulverized by the same mill using the hot combustion gas, whose oxygen content was less than six to nine percent and stored in the pulverized coal bin filled with inert nitrogen gas to prevent spontaneous ignitions and explosions.

When starting operation of the furnace, heavy oil is burned first and after the furnace refractory has reached a proper temperature level, pulverized coal is injected.

The pulverized coal injected into the furnace is ignited first by the ignitor flame, but after several minutes it is ignited by the radiation heat from its own flame to continue burning.

After making sure of the self ignition, the ignitor is shut down and burner operation is adjusted to suit the test conditions scheduled.

The combustion conditions were changed in the amount of overfire air flow (OFA, which was introduced at the downstream of combustion flame), the primary air to coal ratio (A/C), the oxygen content in flue gas (Ex.O₂), the amount of recirculated gas mixed with secondary air (GM), the amount of recirculated gas flow through SGR nozzle (SGR), the burner load (Load), and the secondary air temperature (T_{2ry} air).

Moreover throughout the combustion tests, burner primary air temperature and pulverized coal fineness remained constant at 80 °C and 70 percent through 200 mesh, respectively.

TEST RESULTS ON U.S. COALS

NOx Emission Characteristics

The relations of NOx emissions to burner operating conditions are shown in Fig. 4-1 to Fig. 4-8.

Effect on NOx Formation by OFA. Fig. 4-1 shows the relation of NOx emissions to the OFA ratio (ratio of overfire air to total air, %). The injection of 20 % OFA reduced NOx values to around 100 ppm in Fig. 4-1.

Effect on NOx Formation by Ex.O₂. Fig. 4-2 shows the relation of NOx emissions to Ex.O₂ (oxygen concentration in flue gas, %) with OFA, and that the NOx emissions increased with Ex.O₂. But the increasing rates of NOx emissions with Ex.O₂ are different with types of the coals.

Effect on NOx Formation by SGR. The relation of NOx emissions to SGR ratio (ratio of recirculated gas injected through SGR nozzles to total air, wt %) is shown in Fig. 4-3. In Fig. 4-3 the NOx emissions are slightly increased with SGR ratio. And, NOx increasing rate with SGR for Midwestern bituminous coal showed largest values among the four U.S. coals.

Generally speaking on the tangential fired low NOx pulverized coal burner, the injection of SGR has a NOx reducing effect when a coal with a high fixed carbon to volatile matter ratio and high nitrogen content usually showing high NOx (particularly the one that has delayed ignition) is burned. However SGR tends to increase NOx when a coal with a low fixed carbon to volatile matter ratio and low nitrogen content usually showing low NOx (particularly the one that has stable ignition) is burned.

Effect on NOx Formation by GM. The relation of NOx emissions to GM ratio (ratio of recirculated gas mixed with secondary air to total air, wt %) is shown in Fig. 4-4. In Fig. 4-4, NOx emission is not changed with GM ratio except Western subbituminous coal. In case of Western subbituminous coal, NOx emission increases by about 10 ppm with seven percent increase in GM ratio.

Effect on NOx Formation by Primary Air to Coal Ratio. The relation of NOx emissions to primary air to coal ratio (ratio of the weight of primary air flow through the coal nozzles to that of coal firing rate, kg/kg) is shown in Fig. 4-5.

In Fig. 4-5, NOx emission is slightly increased with the increase in the primary air to coal ratio except Midwestern bituminous coal. In case of Midwestern bituminous coal, NOx emission sharply increases with primary air to coal ratio larger than 2.1.

Effect on NOx Formation by Secondary Air Temperature. Fig. 4-6 shows the relation of NOx emission to secondary air temperature. By increase in secondary air temperature, combustion flame temperature will be increased and then NOx formation due to nitrogen in air should be increased.

In Fig. 4-6, NOx emission is increased with secondary air temperature in case of Texas lignite. But, in case of Eastern and Midwestern bituminous coals the NOx emissions are roughly constant with change in secondary air temperature.

Effect on NOx Formation by Combustion Rate. The relation of NOx formation to the combustion rate which means burner load (ratio of actual coal flow to designed coal flow, %) is shown in Fig. 4-7. And the load is changed simulating the standard mill operation in actual pulverized coal fired boilers. In Fig. 4-7, the NOx emission is almost constant with change in the burner load.

Effect on NOx Formation by Steam Injection. In case of Texas lignite and Western subbituminous coal the moisture content are 25 to 35 percent in coals. When these coals will be burned with unit system (direct system from pulverizer to pulverized coal burner), the moisture contents in the coals are vaporized in the pulverizer and transported with primary air and coal to the burner. In case of the bin system which is the system of the MHI test furnace, primary air for pulverizing in mill and that for transporting the pulverized coal to burner are different, and the primary air and coal in unit system does not contain such a high vaporized moisture.

Steam was injected into coal pipe and was mixed with primary air and coal to simulate the unit system by use of the bin system in the MHI test furnace. Fig. 4-8 shows the relation of NOx productions to steam injection rate (ratio of the injected steam flow to pulverized coal flow, $\text{kg/kg} \times 100$) for Texas lignite.

In Fig. 4-8, NOx level slightly increases with steam injection rate.

Unburned Carbon in Fly Ash

The unburned carbon in fly ash is a very important item to evaluate low NOx combustion technique because of not only to keep the high combustion efficiency but also to be able to utilize the fly ash for cement industries in which carbon percent less than five percent is usually requested.

Fig. 5 shows the relation between unburned carbon in fly ash and NOx emissions for the four coals. Here, the higher values of NOx emission imply the combustion condition without overfire air at high excess air combustion and the lower with overfire air at low excess air combustion respectively.

In Fig. 5, unburned carbon in fly ash with Texas lignite is very low and nearly constant independent of the level of NOx emissions.

Moreover in Fig. 5, Western subbituminous coal has properties of not only low NOx production but also good combustion (low unburned carbon in fly ash). And also it is characterized that Western subbituminous coal is able to keep low NOx emission level with and without overfire air by use of the low-NOx PM burner.

In Fig. 5 unburned carbon in fly ash with Midwestern bituminous coal increases with decreasing NOx emissions. When the NOx emission is around a hundred ppm by use of overfire air, the unburned carbon in fly ash is about two percent. These level of unburned carbon fulfill not only the high combustion efficiency but also the free utilization of the fly ash for cement industries.

In case of Eastern bituminous coal, when the NOx emission decreases from 250 ppm to around 100 ppm the unburned carbon in fly ash increases from 2.4 to 5.5 percent by injection of overfire air with low excess air combustion. The Eastern bituminous coal is characterized to have the lowest burning properties among the four U.S. coals used. From the test results in Fig. 5 the minimum achievable NOx emission for Eastern bituminous coal is limited to about 108 ppm by unburned carbon in fly ash less than five percent.

The relation of NOx emissions to unburned carbon in fly ash, unburned carbon ratio (ratio of unburned carbon to fixed carbon, %) and combustion efficiency are shown in Table 4.

From Table 4, it is obvious that high combustion efficiency with low NOx production can be realized for four U.S. coals when using coal fired PM burner.

Burner Flame Condition

Burner flame conditions are shown in Fig. 6. These figures show the ignition condition and the flame pattern of Midwestern bituminous coal using the pulverized coal fired low-NOx PM burner. The other three coals showed a similar ignition and flame pattern.

From these photographs it is obvious that the pulverized coal fired low-NOx PM burner is able to keep not only low NOx level but also stable ignition and good combustion in the volatile matter combustion zone.

Flame Temperature Distribution

Temperature distributions measured by optical pyrometer in the direction of flame axis comparing with the four coals is shown in Fig. 7. From this figure peak temperatures of combustion flame and length of the peak temperature point from burner front are 1300 to 1400 (°C) and 3.5 to 4.5 (m) respectively.

Heat Flux Distribution

Heat flux distributions measured by heat flow meter in direction of flame axis is shown in Fig. 8.

The firing condition in Fig. 8 is with overfire air. Values of the maximum heat flux in this figure is different in each coal due to the difference in fuel heat input, because of the coal flow rate was kept constant at around 3000 kg/h regardless of the different high heating value of each coal.

PREDICTION OF NO_x EMISSIONS IN FULL-SCALE TANGENTIAL-FIRED UTILITY BOILERS

When predicting the NO_x emission levels in actual boiler equipped with the pulverized coal fired low-NO_x PM burner it is required to have a proper understanding of the law of similarity of NO_x productions in pulverized coal flame (which means the effect of burner scale up performance) and correlation of NO_x emission between test results in test furnaces and in actual boilers.

Law of Similarity of NO_x Productions

From the results of the basic tests, most of the NO_x generated by the combustion of pulverized coal is considered fuel NO_x, then it follows that the main factors governing the NO_x emission level are;

- (1) Quantity of volatile matter vaporized in the ignition zone.
- (2) Distribution of O₂ concentration in the volatile matter combustion zone and char combustion zone.
- (3) Residence time of combustibles in individual combustion zone from ignition zone to char combustion zone.

Therefore, the necessary conditions of the model burner for simulating the NO_x formation characteristic of the actual burner are;

- (1) Radiative heat flux value to the primary air/coal mixture in the ignition zone shall be the same as that of the actual burner.

- (2) The diffusion and mixing pattern of secondary air in the volatile matter combustion zone and char combustion zone shall be the same as that of the actual burner.

The radiative heat flux value in case of the model burner tends to be less than actual one due to the reduced size of flame. The furnace wall of the test furnace should, therefore, be properly lined with refractory so as to make this value the same in both the model burner and the actual burner.

The burner structure should be determined in the following concept to maintain the similarity of the diffusion and mixing pattern of the secondary air (6).

$$[W_F/u_1^3] = \text{const.} \quad (1)$$

$$[u_2/u_1] = \text{const.} \quad (2)$$

$$[W_F/d_n^3] = \text{const.} \quad (3)$$

where

W_F : Coal flow (kg/h)

u_1 : Primary air velocity (m/s)

u_2 : Secondary air velocity (m/s)

d_n : Representative nozzle diameter (m)

Formulas (1) and (2) or formulas (1) and (3) show the law of similarity for coal burners with regard to the formation of NO_x (6).

Correlation of NO_x Emissions between Test Furnace Trials and Actual Boilers

Fig. 9 shows a comparison of the results of the NO_x emission of a three types of model burners and comparison of NO_x emissions of the laboratory test of model burners scaled down following the law of similarity and the field test of conventional burners or SGR burner (which was developed before the developing of the PM burner and was equipped in two 500 MW pulverized coal fired boilers) on actual boilers.

NO_x reduction from conventional burner is around 35 percent by SGR burner and around 65 percent by the PM burner.

On the correlation of NO_x emissions between test furnace and actual boilers, they show a good coincidence with each other in case of the conventional burners. But, in case of the SGR burner they do not show so good coincidence because of the kind of coals used in laboratory test and actual boilers are greatly different from.

Fig. 10 also shows a comparison of NO_x emissions of SGR burner between laboratory tests and fields tests with same types of coals. Although the NO_x emission levels by the burner in service are different in case of the field tests, it is obvious that on the correlation between test furnace and actual boilers they show a good coincidence with each other.

Fig. 11 shows a comparison of unburned carbon content in fly ash between the laboratory tests and fields tests, and they show a good coincidence with each other.

CONCLUSIONS

By a series of tests conducted at MHI's 4 ton/hour test furnace, low-NO_x PM burner proved excellent results as expected for typical U.S. coals covering from Eastern bituminous to Texas lignite.

Low-NO_x levels ranging from 80 to 120 ppm (corrected to 3% O₂) for the four U.S. coals were obtained in the 4 ton/hour test furnace maintaining good combustibility and flame stability.

The results will be able to be used in the prediction of actual boilers by elaborately studying the design and operating conditions. Thus, MHI's low-NO_x PM burner technology can be an effective and useful countermeasure to the even more stringent future EPA NO_x emission regulations (NO_x emissions of 0.2 lb/million Btu).

ACKNOWLEDGEMENT

Mr. M. W. McElroy, the EPRI Project Manager, and Mr. K. Moori of EPDC have substantially contributed to the successful completion of this project.

Moreover, a large number of people were involved in this project and it would be difficult to recognize each person properly. However, we do wish to thank each persons at Combustion Engineering, Inc., Electric Power Development Co. and Mitsubishi International Corp.

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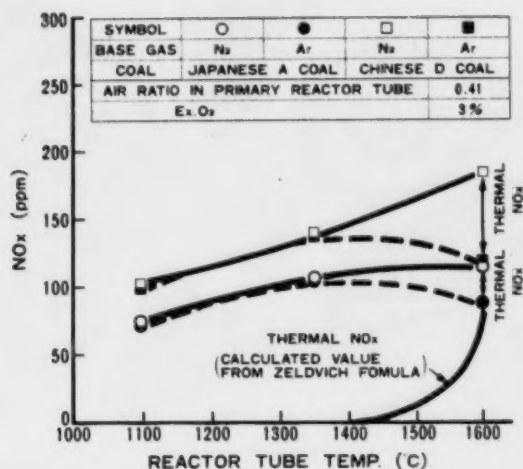


Fig. 1-1 Relation between NO_x production and gas temperature

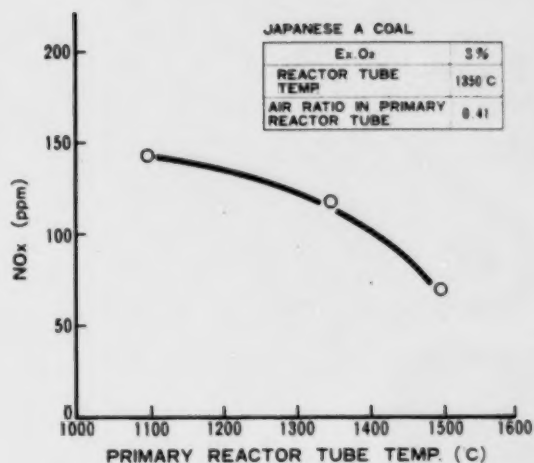


Fig. 1-2 Relation between NO_x production and primary reactor tube temperature

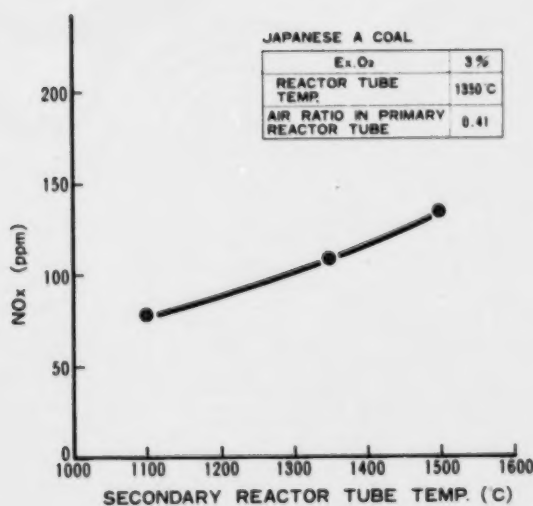


Fig. 1-3 Relation between NO_x production and secondary reactor tube temperature

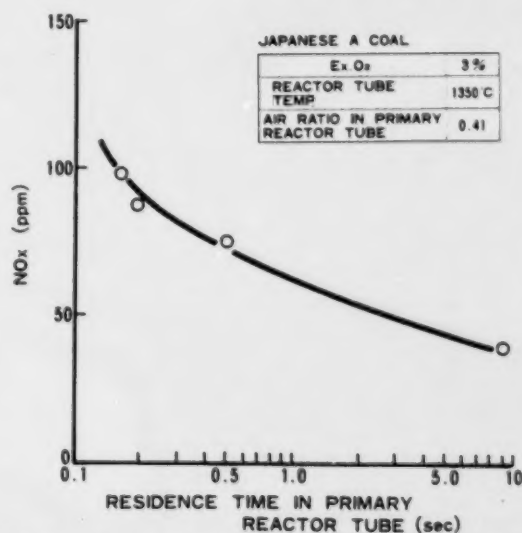


Fig. 1-4 Relation between NO_x production and residence time in primary reactor tube

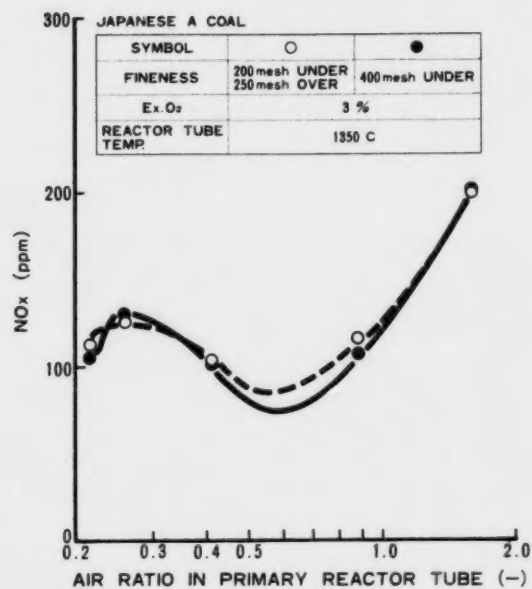


Fig. 1-5 Relation between NO_x production and fineness

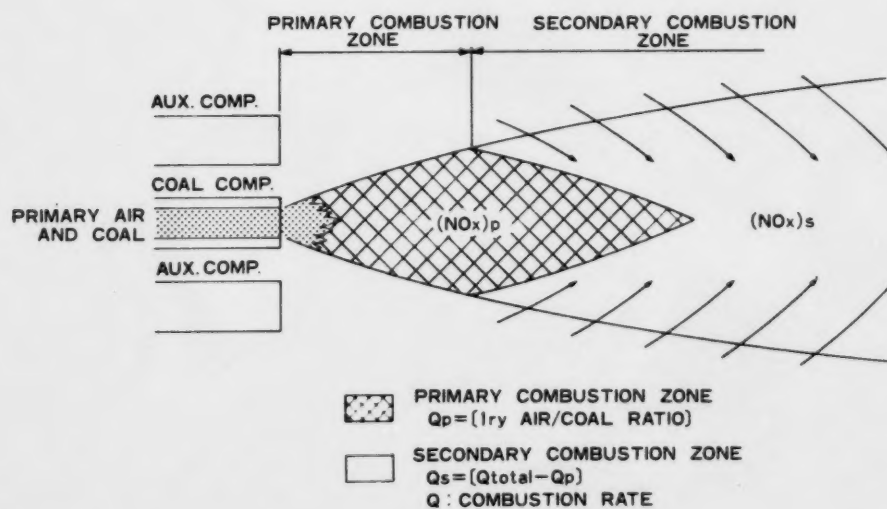


Fig. 2-1 Combustion model of pulverized coal

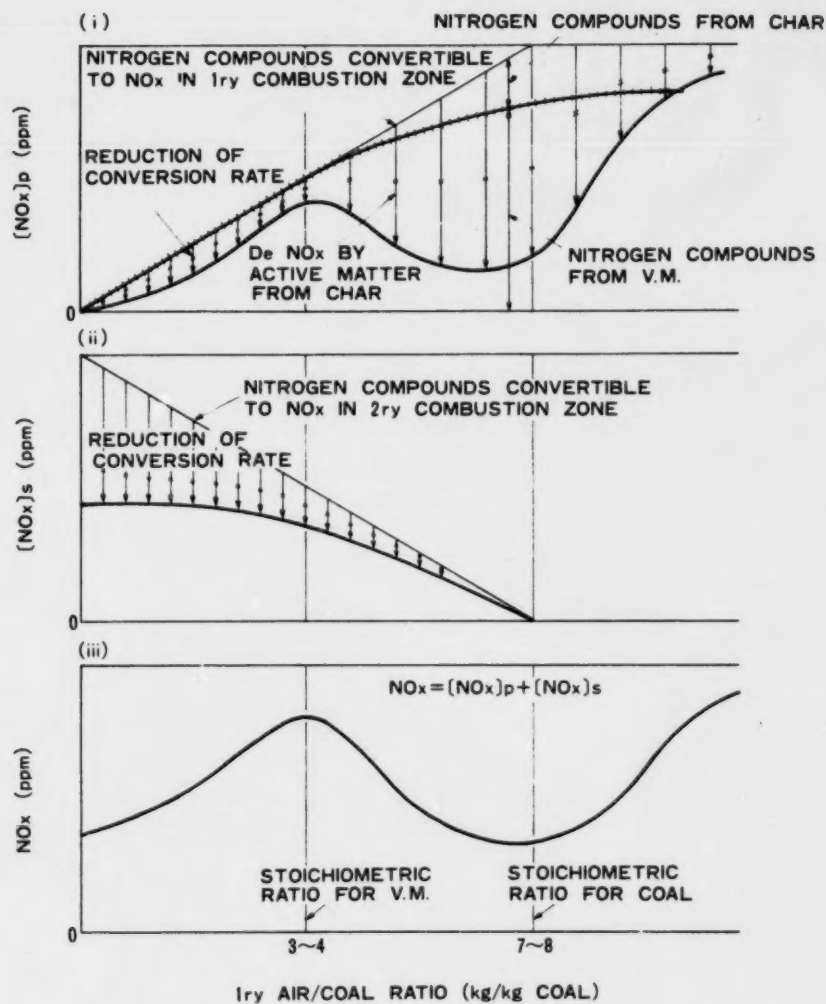


Fig. 2-2 NO_x formation characteristics with 1ry air/coal ratio

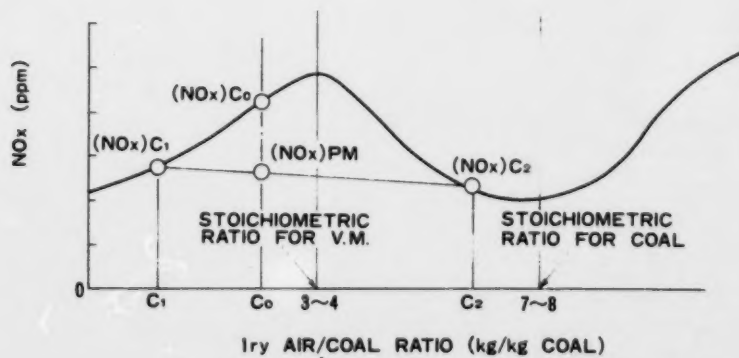


Fig. 2-3 Concept of pulverized coal fired low- NO_x PM burner

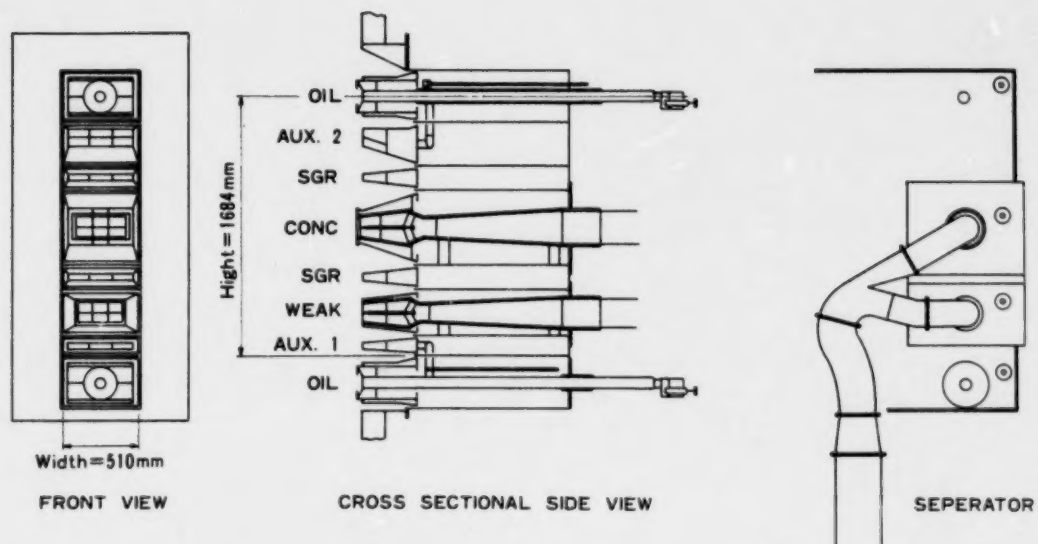


Fig. 2-4 Structure of coal fired low-NOx PM burner used

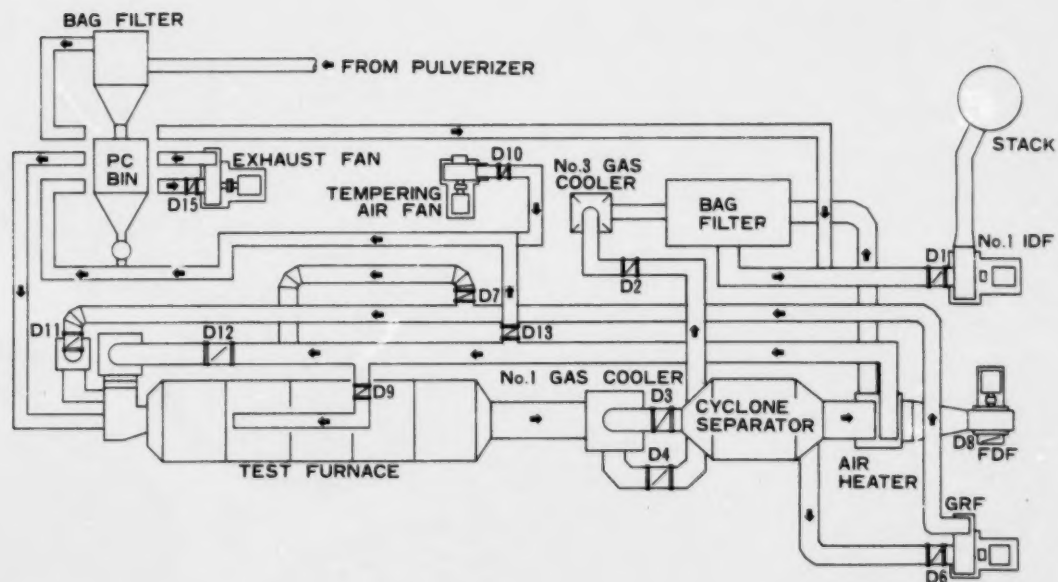


Fig. 3 Flow sheet of MHI's 4 ton/hour pulverized coal fired test furnace

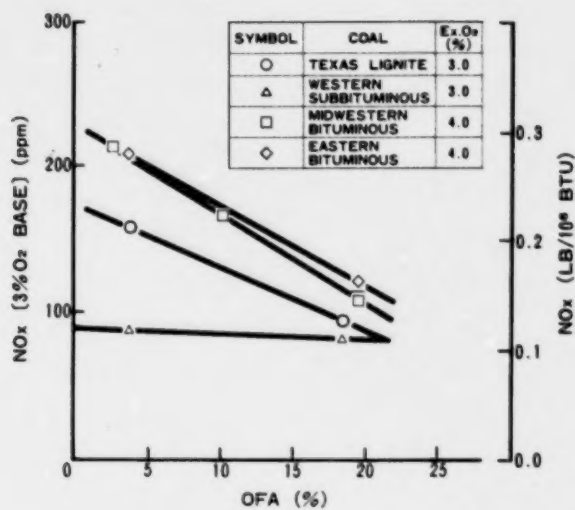


Fig. 4-1 NOx vs. OFA

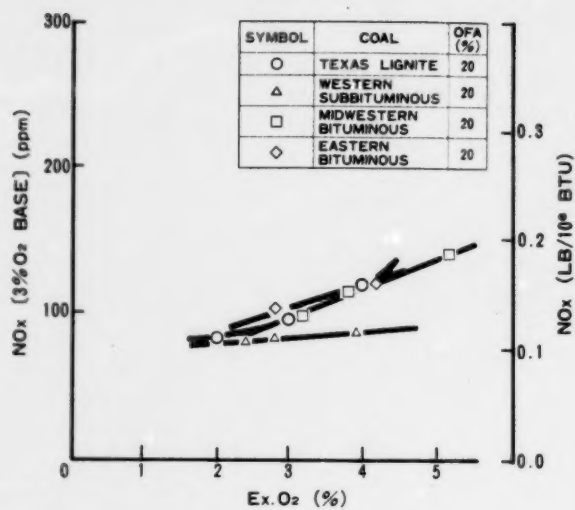


Fig. 4-2 NOx vs. Ex. O₂ (OFA = 20%)

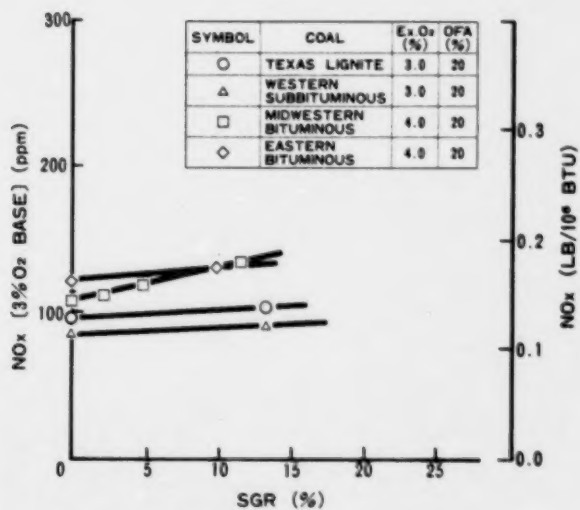


Fig. 4-3 NOx vs. SGR

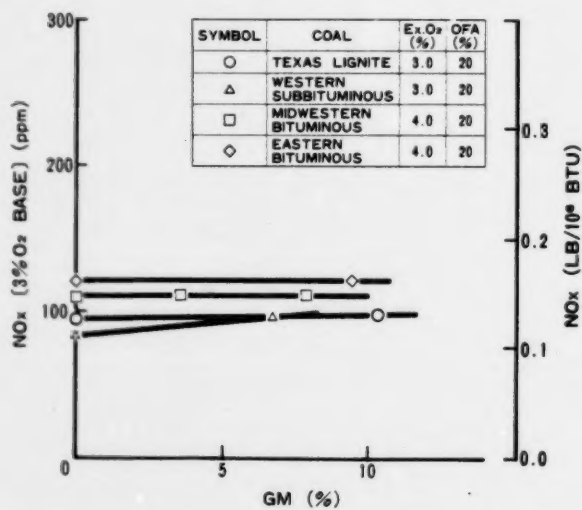


Fig. 4-4 NOx vs. GM

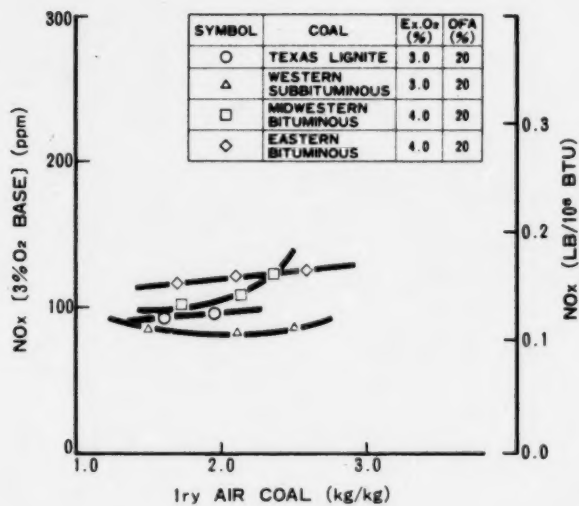


Fig. 4-5 NOx vs. 1ry air/coal ratio

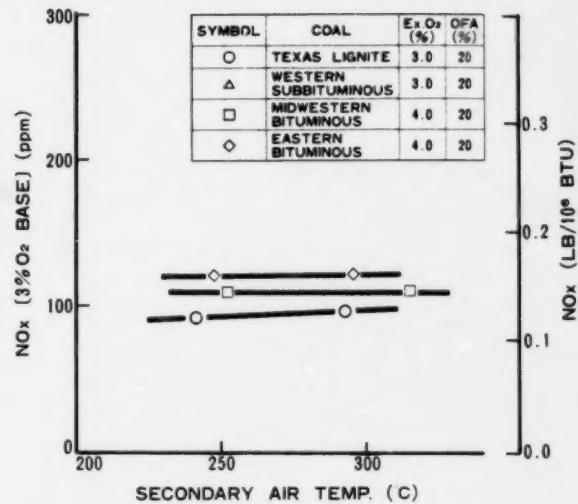


Fig. 4-6 NOx vs. secondary air temperature

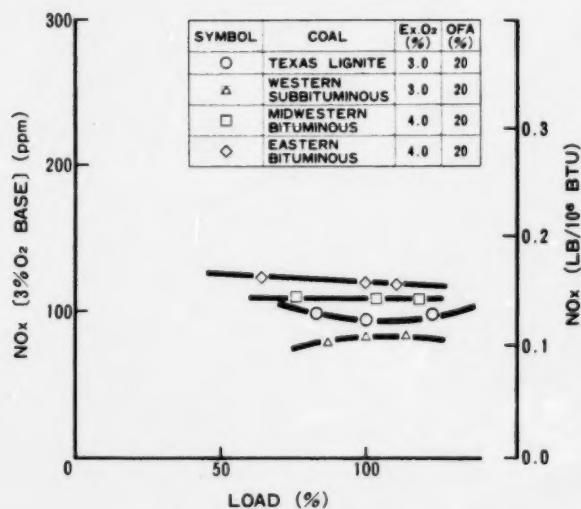


Fig. 4-7 NOx vs. burner load

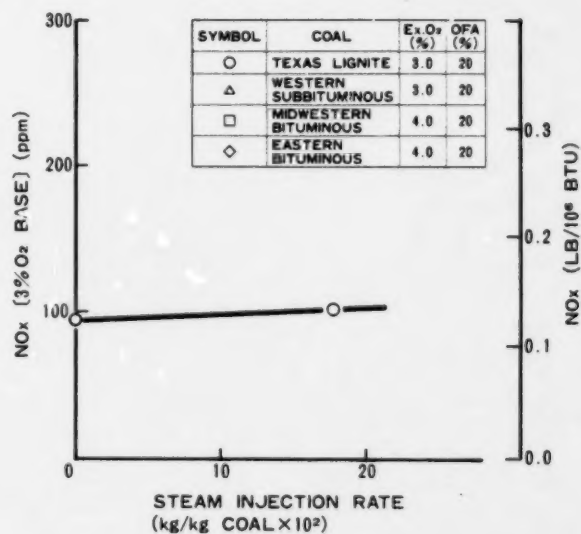


Fig. 4-8 NOx vs. steam injection rate

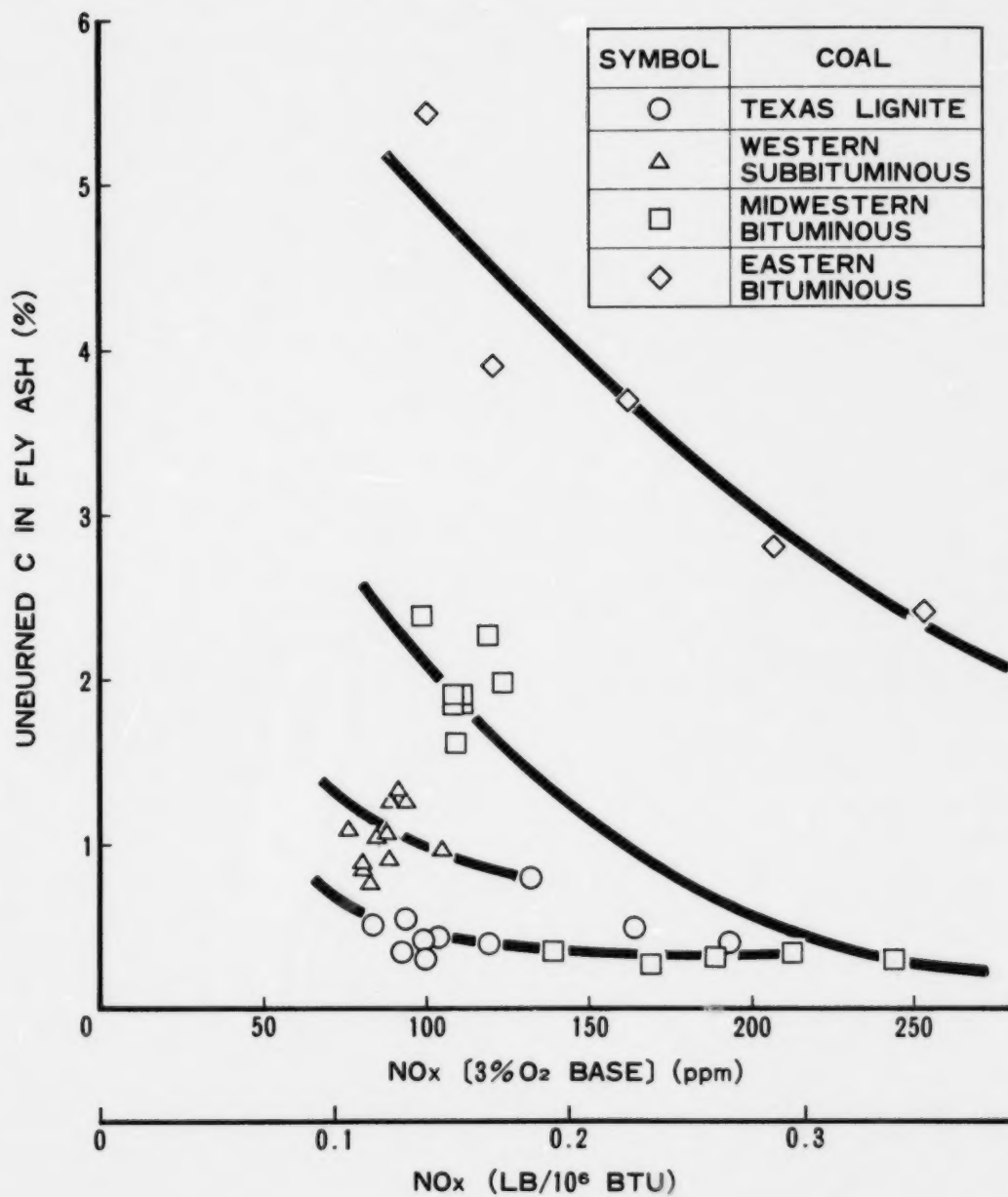
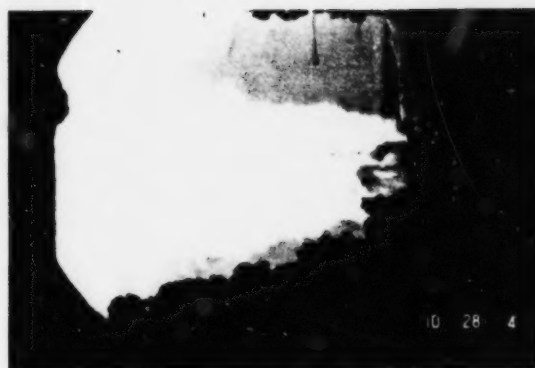
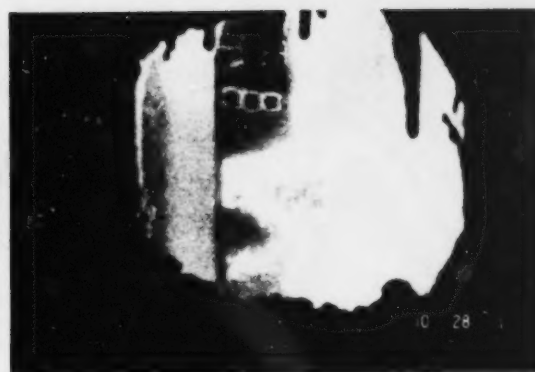


Fig. 5 Unburned C in fly ash vs. NO_x



SIDE VIEW OF THE FLAME NEAR
THE BURNER FRONT



FRONT VIEW OF THE FLAME AROUND
THE BURNER FRONT

Fig. 6 Flame of pulverized coal fired low-NO_x PM burner
with Midwestern bituminous coal

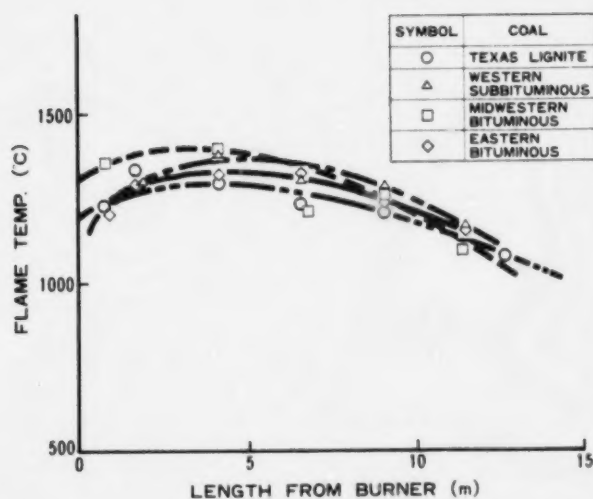


Fig. 7 Flame temperature distribution
along to flame axis (With OFA)

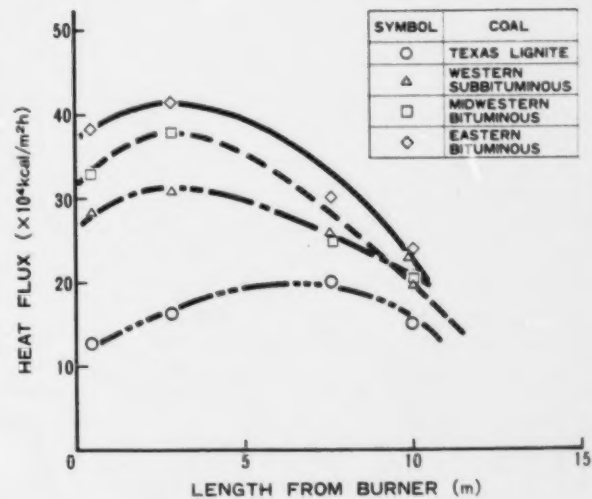


Fig. 8 Heat flux distribution along
to flame axis (With OFA)

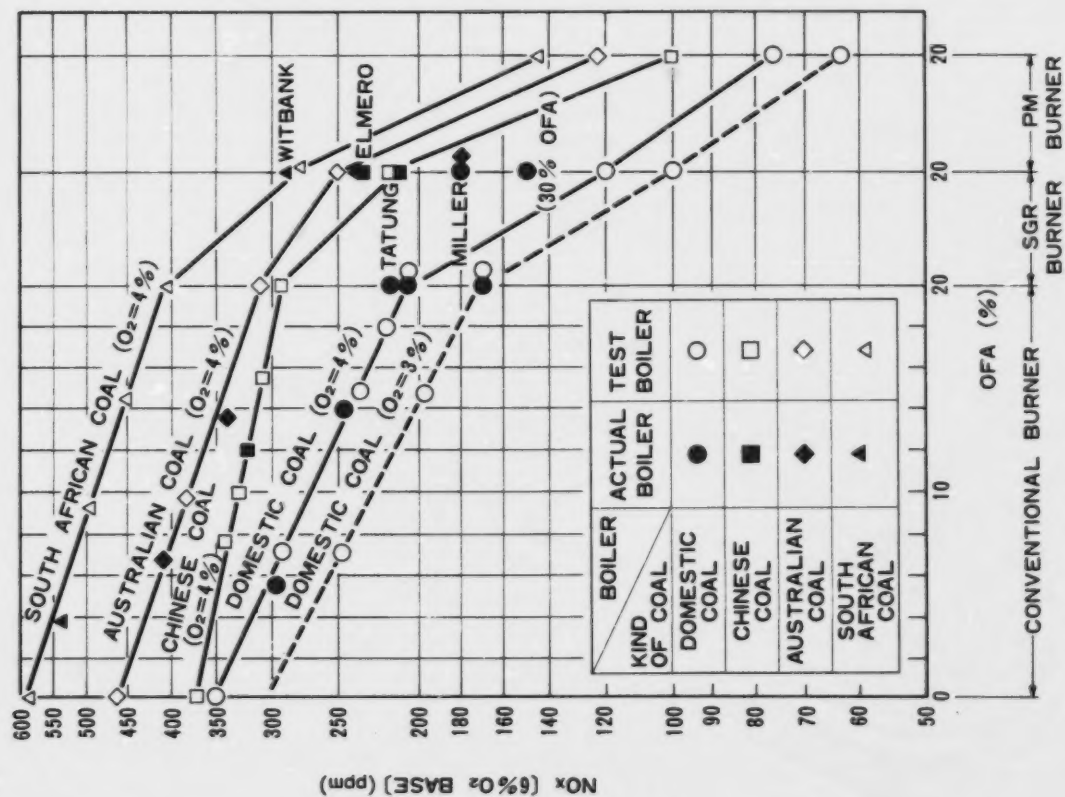


Fig. 9 Comparison of NOx emission laboratory test results vs. field data

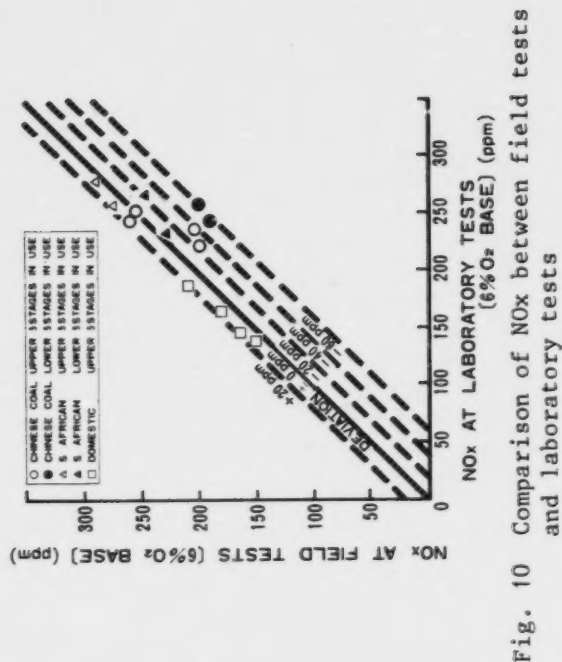


Fig. 10 Comparison of NOx between field tests and laboratory tests

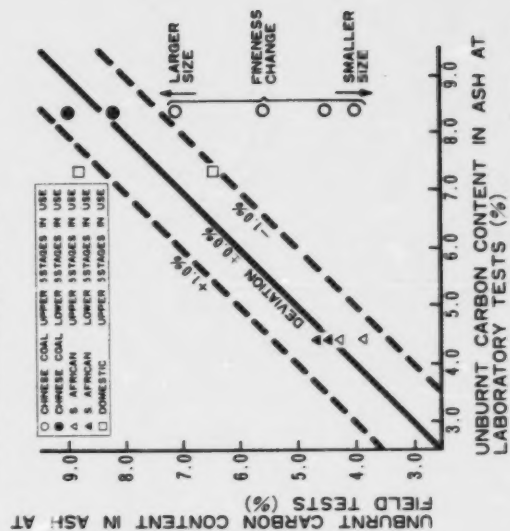


Fig. 11 Comparison of unburned carbon content in fly ash between field tests and laboratory tests

Table 1 ANALYSES OF FOUR U.S. COALS TESTED

Item \ Unit		Texas lignite	Western subbituminous coal	Midwestern bituminous coal	Eastern bituminous coal	
HHV (Dry)		4900	5960	6550	7520	
Surface moisture		16.0	8.3	0.3	0.5	
Proximate analysis (Dry base)	Inherent moisture	15.8	13.1	8.7	2.3	
	Fixed carbon	33.0	45.2	46.0	52.9	
	Volatile matter	37.3	37.1	35.8	36.3	
	Ash	13.9	4.6	9.5	8.5	
	Total	100.0	100.0	100.0	100.0	
	Total S	1.12	0.41	2.94	0.69	
	Fuel ratio (FC/VM)	0.88	1.22	1.28	1.46	
Ultimate analysis (Moisture free)	C	57.7	72.3	71.6	81.2	
	H	4.5	4.9	5.0	5.5	
	O	19.7	16.2	8.6	2.3	
	N	1.01	1.20	1.27	1.60	
	S (combustible)	0.54	0.14	3.13	0.68	
	S (uncombustible)	0.79	0.33	0.09	0.03	
	Cl	67	47	518	936	
Coal properties	F	34	31	74	49	
	Grindability	HGI	47	50	51	45
	Specific gravity	1.443	1.451	1.474	1.275	
	Specific heat	0.265	0.267	0.285	0.268	
	Free SiO ₂	2.8	0.7	—	1.1	
	Fusibility (DM/ASTM)	Softening temp.	1195	1285	1235	1500
		Fusion temp.	1235	1335	1355	>1500
Fluid temp.		1310	1355	1420	>1500	

Table 2 MAIN FEATURES OF 4 ton/hour PULVERIZED COAL FIRED TEST FURNACE

Equipment		Technical details
Test furnace		Horizontally installed, water cooled, circular-walled steel construction, 4.4 diameter, 20m length
Fan	F.D.fan	Capacity : 920m ³ /min × 800mmAq at 20°C, Motor : 160kw
	No.1 I.D.fan	Capacity : 1140m ³ /min × 800mmAq at 100°C, Motor : 330kw
	No.2 I.D.fan	Capacity : 200m ³ /min × 320mmAq at 100°C, Motor : 30kw
	Exhaust fan	Capacity : 260m ³ /min × 700mmAq at 100°C, Motor : 90kw
	G.R.fan	Capacity : 760m ³ /min × 600mmAq at 350°C, Motor : 165kw
Air Heater		Ljungstrom type, Capacity : 750Nm ³ /min × (25→350°C)
Gas cooler	No.1 Gas cooler	Water cooled tubular type, Capacity : 750nm ³ /min × (800→500°C)
	No.2 Gas cooler	Water cooled tubular type, Capacity : 200nm ³ /min × (700→120°C)
	No.3 Gas cooler	Water cooled tubular type, Capacity : 100nm ³ /min × (700→350°C)
Ash disposal	Cyclone separator	Multi-cyclone type, Capacity : 1000nm ³ /min × 500°C
	Bag filter	Filter area 613m ² , Capacity : 1200nm ³ /min × 120°C
	Precipitator	Gas velocity : 1~1.5m/s, Capacity : 2500nm ³ /h
Fuel feed assembly	Coal pulverizer	Bowl mill type, Capacity : 2300hg/h × 8000m ³ /h × 600mmAq
	P.C.bin	Capacity : 20m ³
	P.C.feeder	Table feeder type, Capacity : Max 4500kg/h

Table 3 MEASURING ITEMS AND INSTRUMENTS

Measuring item		Instrument	Measuring position
Coal feed		Load cell	P.C. bin
Fineness of P.C.		JIS sieve ^a	Outlet of mill
Analyses of flue gas	O ₂	Zirconia cell	Outlet of furnace
	NO	Chemiluminescence	Outlet of furnace
	CO	Dräger sensor	Outlet of furnace
	CO ₂	N.D.I.R. method ^b	Outlet of furnace
	SO _x	Neutralization method	Outlet of furnace
	HCL	Calorimetric method (Mercuric Thiocyanate method)	Outlet of furnace
	HF	Calorimetric method (Lanthanum Alizarin Complexion method)	Outlet of furnace
Unburned carbon in fly ash		JIS standard ^a	Multicyclone & bag filter
Temperature of flame		Optical pyrometer	Peep hole of furnace
Heat flux		Heat flow meter	Peep hole of furnace
Combustion air flow		Orifice meter	Air duct
Recirculated gas flow		Orifice meter	Recirculated gas duct

Note

^a Japanese Industrial Standard

^b Non-divergent Infra-red

Table 4 RELATION OF NO_x EMISSION TO COMBUSTION EFFICIENCY

Coals	Texas lignite	Western subbituminous	Midwestern bituminous	Eastern bituminous
NO _x (ppm) [3%O ₂ basis]	95	82	106	120
Unburned carbon in fly ash (%)	0.5	1.0	1.8	3.9
Unburned carbon ratio (%)	0.2	0.1	0.38	0.66
Combustion efficiency (%)	99.86	99.94	99.78	99.62

FEASIBILITY STUDY OF A LOW-NO_x RETROFITTABLE FIRING SYSTEM
WITH U.S. COALS

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ABSTRACT

A feasibility study for application of the "PM" firing system to new and retrofit tangentially fired utility boilers has been completed. The study has shown that the "PM" firing system is applicable to existing and new utility boilers. The ease and costs of installation are proportional to the level of NO_x emissions guarantee required.

INTRODUCTION

Since 1972, Combustion Engineering has utilized an air staging technique for NO_x emission control on new coal fired steam generators. The technique withholds 15-20% of the air conventionally supplied to the furnace fireball and injects this air over the flame envelope, through overfire air compartments. This approach reduces the level of fuel NO_x emissions by limiting the oxygen available to react with the fuel bound nitrogen during the initial stages of the combustion process. Currently, NO_x reductions of approximately 25% are obtained in tangentially fired utility boilers by incorporating overfire air (OFA) compartments. To obtain further NO_x emission reductions, studies have indicated that larger quantities of combustion air must be staged at the point of initial coal devolatilization.

Pursuing this goal, Takahashi¹ has shown that two separate flames, one fuel lean premixed flame plus one fuel rich diffusion flame can be combined to produce a lower NO_x emission than either type flame with the same overall stoichiometry. The Mitsubishi Heavy Industries (MHI) Low NO_x PM Burner System exploits this NO_x reduction concept through the use of fuel rich and fuel lean coal compartments. The detailed operating characteristics of the PM burner are presented in the preceding companion paper.

The PM coal firing system currently provides NO_x emission reductions greater than 50%, compared to conventional tangentially fired boilers. This PM firing system has been licensed to C-E for exclusive application in steam generators for the U.S. and Canada. To provide a thorough assessment of the engineering and

economic implications for applying the "PM" firing system on tangentially fired U.S. utility boilers, an EPRI sponsored feasibility study for both a new unit and retrofit basis, was conducted by Combustion Engineering.

FEASIBILITY STUDY APPROACH

The goal was to provide an economic evaluation along with an engineering assessment, for installing this system on both a new unit and retrofit unit basis. To insure an analysis for typical installations, the specific sites selected for this evaluation were limited to modern tangentially fired utility boilers with a minimum power generating capacity of 500 MW. The specific boilers selected were also limited to firing only coal previously tested by MHI during the low NOx combustion test program of U.S. coals in Nagasaki, Japan (see preceding companion paper).

The four "PM" firing system options shown in Figure 1 each provide a different magnitude of NOx reduction. These configurations differ by the OFA compartment arrangements, either integral or separate, and whether or not additional space is provided between adjacent coal compartments. For the retrofit assessment, the selected approach evaluated two configurations, representing the minimal cost case; Case I, and the highest cost case; Case II. Due to the anticipated higher costs of retrofitting taller windboxes resulting from separate OFA compartments, the two options selected for analysis both utilized integrated OFA compartments. The host boiler selected for these two retrofit applications, Plant A, had existing OFA compartments to ease the installations.

In addition to these installations, a third retrofit application, Case III, was evaluated. The selected host boiler, Plant B was a divided furnace with OFA compartments. Inherently divided furnaces limit the fuel pipe arrangements for windboxes along the centerwall. Therefore to minimize further modifications and retrofit costs, the "PM" windbox for this installation was designed as short as possible while maintaining the existing windbox width.

For the new unit assessment, the selected approach provided the minimum NOx emission level without adding excessive costs to the new unit design. An existing boiler, Plant A was chosen as a model for this task. All costs for this new unit installation were obtained for present day erection of this boiler with both the conventional firing system and the "PM" firing system. Comparison of these costs provided the additional capital installed cost for the "PM" firing system.

To assist in selecting the "PM" windbox arrangements for both the retrofit and new unit installations, C-E computer programs were utilized to predict modifications required for obtaining the design steam flows. These modifications included changes to both the heating surfaces and the windbox tilts. Proposition type drawings were prepared for the retrofit and new unit applications to assist in the generation of cost estimates. The cost estimates have an accuracy of $\pm 20\%$, and were prepared with the EPRI economic analysis guidelines contained in "Economic Premises for Electric Power Generating Stations" revised June 1, 1981.

ENGINEERING FEASIBILITY

Some features of the "PM" firing system significantly impact the ability to retrofit the system. The most influential feature which may in some instances require pressure part modifications to the host boiler is the overall height

of the "PM" windbox assembly. The structure of this firing system requires twice as many, but smaller, coal compartments as the conventional system, and in some instances also requires providing a separation between adjacent coal compartments. To install this firing system while minimizing pressure part modifications, has required maintaining the host boiler windbox compartment width and extending the overall windbox height. However, the extent of "PM" windbox induced modifications and retrofit costs would always be determined by the degree of conservatism utilized for the original design of the host boiler.

For new unit applications, the "PM" windbox overall height also significantly effects the furnace design. However on a new unit basis, installation of the taller "PM" firing system would be more cost effective than on a retrofit basis.

RETROFIT APPLICATIONS

Plant A - Single Furnace

Plant A is a 600 MW, controlled circulation radiant reheat, balanced draft, utility boiler, producing 4,200,000 lb. primary steam/hr. Six elevations of tilting tangential fuel admission assemblies supply a sub-bituminous coal to the boiler. Provision for an additional fuel elevation was included in the windbox for future lignite firing.

Retrofit - Case I. The initial "PM" firing system retrofit at Plant A, Case I, was designed for minimal boiler modifications. This goal was attained by using option C of Figure 1 to provide a retrofit windbox compatible with the existing furnace waterwall openings. The existing windbox at Plant A was designed for future lignite firing, therefore this constraint was eased. Specifically, the existing design included a blanked off coal compartment at the bottom of each windbox which was utilized for the retrofit "PM" windbox. Figure 2 illustrates both the "PM" retrofit windbox and the existing windbox designs.

The retrofit windbox significantly changed the coal nozzle spacing and the burner heat release zone. Figure 3 illustrates both the retrofit and conventional windbox heat release zones. To provide a comparison of the convective pass gas temperatures the lower furnace heat absorption profile was used along with the retrofit and conventional windbox heat release zones. This computer analysis has shown the gas temperature to the superheater division panel increased by 28°F (16°C) with the retrofit windbox. Also, the average vertical furnace gas outlet temperature to the superheater pendant platen increased by 22°F (12°C) with the retrofit windbox. Unless corrected, these gas temperatures would result in higher superheat and reheat steam temperatures.

By utilizing the windbox tilts, a solution was determined. Specifically, a 3° windbox downtilt would maintain the furnace gas outlet temperature to the superheat and reheat panels at the design levels. This procedure was an acceptable option for maintaining the existing heat absorption and the boiler efficiency. On this basis, costs for retrofitting this windbox at Plant A were evaluated.

Retrofit - Case II. The Case II-"PM" Firing System retrofit at Plant A was designed for a minimum attainable NOx level without excessive retrofit costs. Providing the lowest attainable NOx emission level would require widely spaced

fuel compartments and separating the OFA compartments from the fuel and auxiliary air compartments, depicted by option D of Figure 1. Specifically, the OFA compartments would be positioned several feet above the upper coal nozzle and would induce slightly lower NOx emissions by further staging the oxygen essential for complete combustion. This arrangement would require boiler waterwall modifications. Also, convective and radiant heating surface modifications would be required for the extended heat release zone. Due to the modifications required and excessive costs for separate OFA compartments while providing minimal additional NOx reductions, the "PM" firing system for this second retrofit at Plant A instead utilized option A of Figure 1 with integrated OFA compartments. This windbox is illustrated in Figure 4.

Installation of this 18 ft. extended windbox would significantly change the coal compartment spacing, and the heat release zone. Figure 5 illustrates the existing windbox and the retrofit windbox heat release zones. Again the lower furnace heat absorption profile was used with the retrofit and existing heat release zones to provide a comparison of the convective pass gas temperatures. This computer analysis yielded a 134°F (74°C) hotter gas temperature to the superheater division panel with the retrofit windbox. Also, the average vertical furnace gas outlet temperature to the superheater pendant platen increased by 91°F (51°C) with the retrofit windbox. These hotter gas temperatures would result in unacceptably high reheat and superheat steam temperatures. Proper boiler operation requires maintaining superheat and reheat steam outlet temperatures at the design levels. Also the stack gas temperature must be maintained at the design level to sustain the steam cycle efficiency.

A possible solution would be to maintain a 30° windbox downtilt and a 2.1 percentage point excess air reduction. However, operating the boiler with these conditions removes all firing flexibility and would not be practical. The other viable option for maintaining boiler efficiency and superheat/reheat steam temperatures required modifying the existing superheat, reheat and economizer surfaces. After carefully analyzing numerous variations only one solution emerged. This included removing 23% of the reheat finishing section surface area, reducing low temperature superheat pendant surface area by 32%, and increasing economizer surface by 16.5%. Figure #6 illustrates these boiler convective pass heating surfaces. Incorporating these modifications along with the "PM" retrofit windbox would maintain the boiler efficiency and superheat/reheat steam temperatures at design levels.

These modifications would not affect the lower furnace heat absorption profile or change the furnace gas outlet temperature. Upper furnace fouling must be considered with these elevated temperatures. Considerable ash buildup and bridging could be expected on the closely spaced superheater pendant platen section. The superheater division panels however are spaced 10 feet apart, therefore only a slight buildup would be expected on these surfaces. To minimize the extent of ash fouling, additional retractable soot blowers would be installed.

Therefore on this basis the costs for retrofitting this windbox at Plant A were evaluated.

Plant B - Divided Furnace

Plant B is a 575 MW, eight corner/divided furnace, supercritical radiant reheat, balanced draft utility boiler, producing 4,003,675 lb primary steam/hr. Eight

C-E bowl mills supply pulverized coal to eight elevations of tilting tangential fuel admission assemblies.

Retrofit Case III. The "PM" system retrofit at Plant B, (Case III), was designed for minimal host boiler modifications. However, the shortest retrofit windbox, arranged per option C of Figure 1 was four feet taller than the existing windbox. Waterwall panel modifications would be required for the installation. To minimize the effect of the longer heat release zone, the retrofit windbox vertical centerline was maintained at the existing location. Figure 7 illustrates the arrangement of this retrofit windbox assembly. The lower furnace heat absorption profile for Plant B was used with the retrofit and conventional heat release zones to provide a comparison of the convective pass gas temperatures. Figure 8 illustrates both the existing and retrofit heat release zones. This computer analysis yielded an 18°F (10°C) hotter average vertical furnace gas outlet temperature to the superheater pendant plante, and a 24°F (13°C) hotter gas temperature to the superheater division panel with the retrofit windbox. With an 8° windbox downtilt, the superheat and reheat outlet steam temperatures along with the stack gas outlet temperature were maintained at the design levels. This was judged an acceptable operating mode and the costs for retrofitting this "PM" windbox at Plant B were evaluated.

NEW UNIT APPLICATION

The new unit application was evaluated using Plant A as the base from which modifications and incremental costs would be determined. The goal was to achieve a minimum NOx emission level without adding excessive costs to Plant A on a new unit basis.

For this application the 18 feet extended windbox previously evaluated for the Case III retrofit installation was utilized. With this retrofit windbox installed at Plant A, previous computer analysis for Case II yielded unacceptably high convective pass gas temperatures. Again, with the high furnace outlet temperature backpass fouling could be expected. On a retrofit basis these higher gas temperatures could not be acceptably lowered without excessively costly boiler modifications. For a new unit installation these design changes would be more cost effective. Generally, on a new unit basis, the furnace gas outlet temperature could be cost effectively lowered to an acceptable level by increasing the furnace height above the windbox. This additional height would provide further waterwall heat absorption surface to reduce the furnace gas outlet temperature. At Plant A, the design furnace gas outlet temperature would be obtained for the 18 feet extended "PM" windbox by increasing the furnace height above the windbox by 18 feet. This design change would also eliminate the potential ash fouling problem. The arrangement of the "PM" windbox at Plant A and the heat release zone for this new unit application is identical to Figures 4 and 5, respectively. On this basis, the costs for present day erection of both the original design furnace and the taller "PM" windbox incorporated furnace was obtained.

NOx PERFORMANCE

The "PM" burner system can provide greater than 50% reduction in NOx emissions for tangentially fired boilers. A summary of the NOx emission levels for the feasibility study is presented in Table A. A NOx emission level guarantee was obtained for all the cases evaluated in the study. The NOx emission guarantee

involves a stepwise approach which relates burner capacity, percent OFA, air/coal ratio, fuel nitrogen conversion rates, fuel nozzle spacing and other variables to NOx emission values. Utilizing this information, a guaranteed NOx emission level was obtained. For the plants analyzed, lower NOx emission guarantees were also technically feasible, but were judged to be economically unattractive.

ECONOMIC EVALUATION

An economic evaluation of the "PM" firing system for new and retrofit installations was conducted by C-E. The evaluation has an accuracy of $\pm 20\%$ and was prepared with the EPRI economic analysis guidelines contained in "Economic Premises for Electric Power Generating Stations" revised June 1, 1981. A summary of this evaluation is presented in Table B.

Retrofit Applications

The minimal cost case, Case I required only one-half the total process capital of the highest cost case, Case II. A blanked off coal nozzle provided the additional space necessary for installation of the Case I windbox at Plant A. This installation did not require either heating surface or structural steel modifications. Whereas installation of the Case II windbox at Plant A required both extensive upper furnace heating surface modifications and structural steel modifications. At Plant B, strategic placement of the Case III windbox avoided both heating surface and structural steel modifications. The higher costs for this application reflect the additional windboxes required for divided furnaces and the change from six to eight fuel elevations.

New Unit Application

The total necessary process capital would be considerably less for a new unit application than installing the identical windbox at the same boiler on a retrofit basis.

CONCLUSIONS

This study has shown that the "PM" firing system can be retrofit on tangentially fired utility boilers. The cost of providing this system on a retrofit basis however is strongly related to the amount of NOx reduction desired and the specific design features of the boiler. As the level of relative NOx reduction increases, the required height of the "PM" windbox increases along with the extent of necessary boiler modifications. These modifications are directly related to changes in the lower furnace heat release zone, and may include but are not limited to, convective and radiant heating surface modifications, waterwall modifications and structural steel modifications. The extent of these modifications significantly affect the cost of the installation. The firing system installation costs are also influenced by the number of fuel admission assemblies.

The retrofit costs are indirectly related to the rank of coal utilized at the boiler. For a specific plant, the number of coal elevations required for a predetermined steam flow increases with decreasing coal rank. By increasing the number of coal elevations, the extension required for a retrofit "PM" windbox also increases. Therefore, on a \$/KW basis the "PM" windbox retrofit costs would generally be expected to increase with decreasing coal rank.

For new unit applications, preconstruction design changes may be utilized to obtain the proper furnace gas outlet temperature, steam flows and boiler steam cycle efficiency. On this basis, the total capital cost for new unit applications would be considerably less than the identical requirements on a retrofit basis.

In summary, the costs for both new unit installations and retrofit installations of the "PM" low NO_x firing system are in general proportional to the relative level of NO_x reduction and inversely proportional to coal rank. However, due to the unique aspects of each new unit and retrofit application, site specific engineering and cost studies are required.

ACKNOWLEDGEMENTS

The assistance of Mitsubishi Heavy Industries, and Electric Power Development Corporation, both of Japan, the Electric Power Research Institute and Combustion Engineering personnel connected with this work is gratefully acknowledged.

REFERENCES

1. Takahashi, Y., et al., Development of Super-Low NO_x PM Burner. Mitsubishi Technical Bulletin No. 134. Mitsubishi Heavy Industries, Ltd., 1979.

PM WINDBOX OPTIONS FOR PLANT A

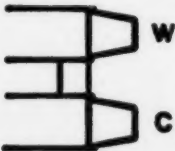
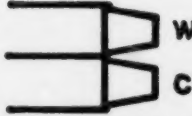
OPTION	A	B	C	D
PURPOSE	150 ppm TARGET	COMPROMISE of A & C	MINIMUM MODIFICATION	MINIMUM NO_x
NO_x GUARANTEE (CORR. TO 3% O₂)	150	179	190	130
WINDBOX HEIGHT (INCHES)	702	600	515	783
OFA LOCATION	INTEGRAL	SEPARATE	INTEGRAL	SEPARATE
COAL NOZZLE SCHEME	SCHEME 1	SCHEME 2	SCHEME 2	SCHEME 1
WINDBOX LAYOUT	 OFA	 OFA	 OFA	 OFA
COAL NOZZLE SCHEME - 1  SCHEME - 2 				

FIGURE 1

RETROFIT LOW NO_x BURNER SYSTEM PLANT A - CASE I

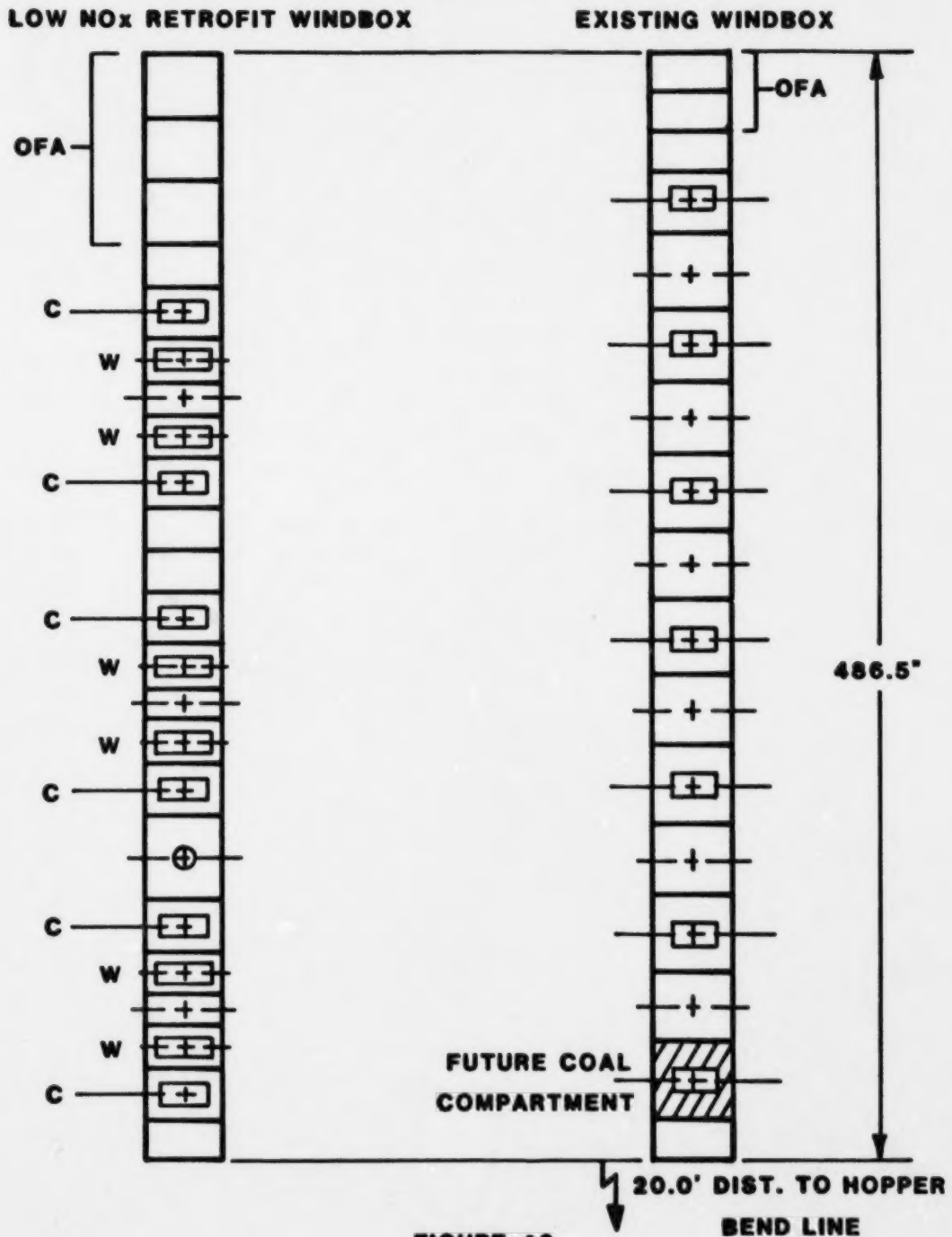


FIGURE #2

**HEAT RELEASE ZONES
PLANT A - CASE I**

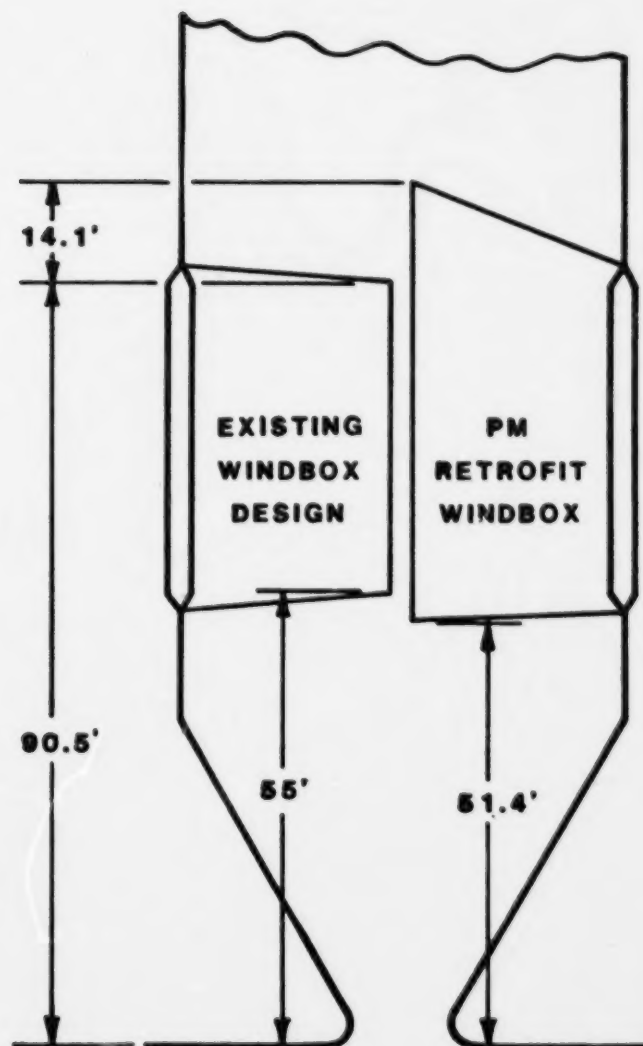
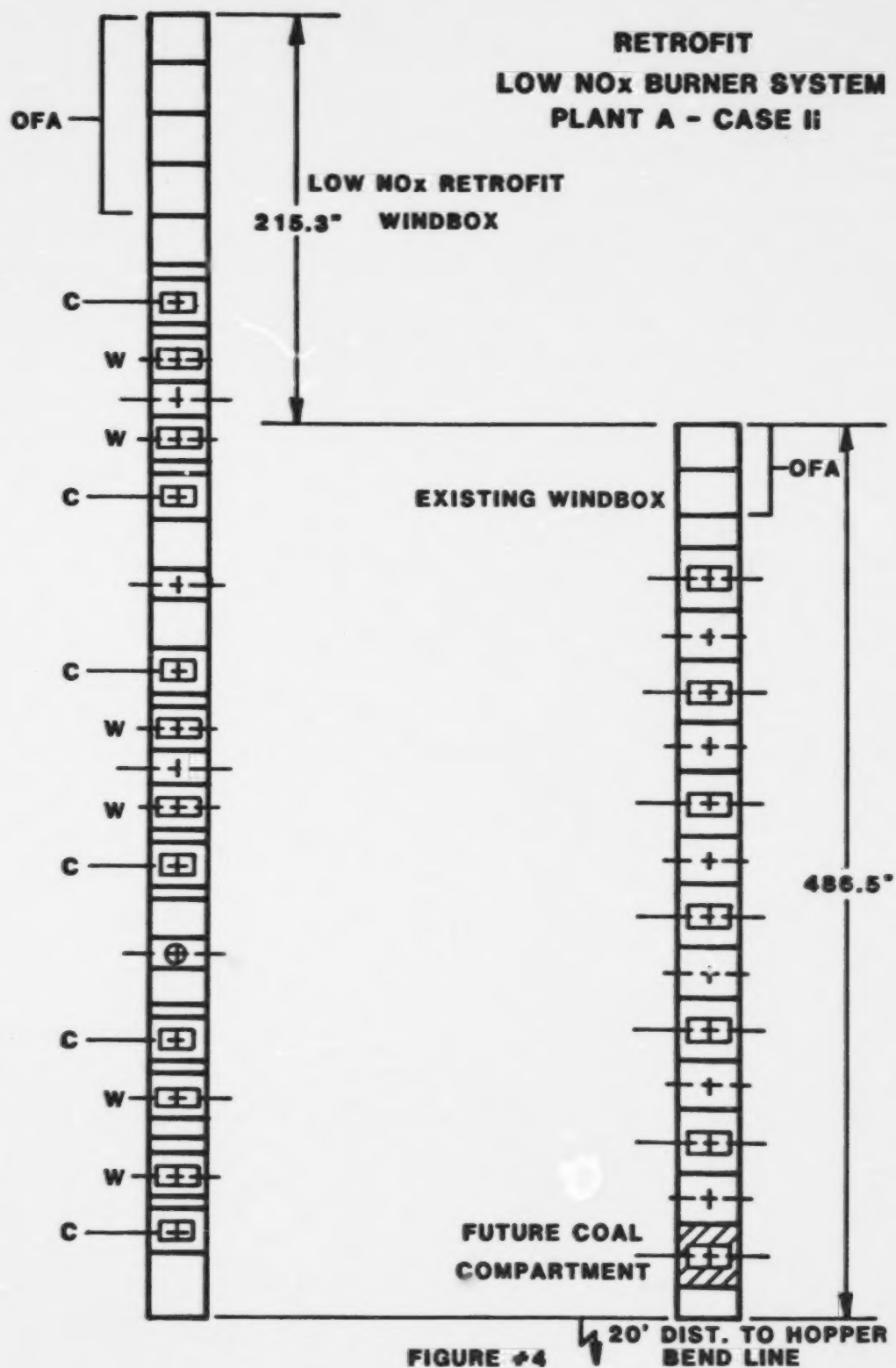


FIGURE #3



**HEAT RELEASE ZONES
PLANT A - CASE II**

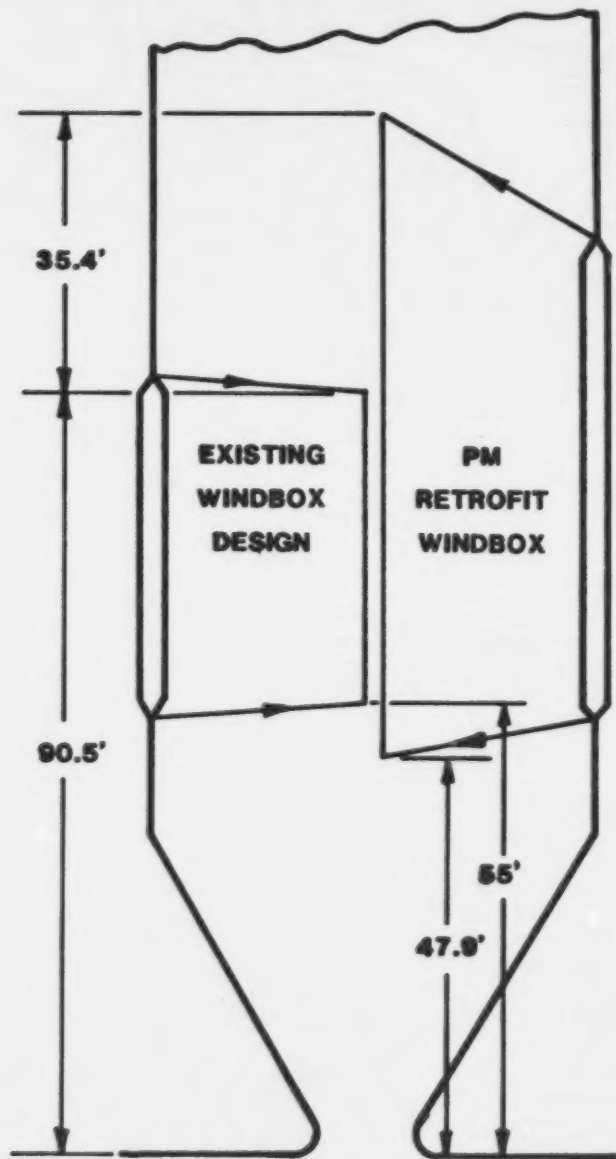


FIGURE 45

LOCATION OF PLANT A - HEATING SURFACE MODIFICATIONS FOR PM CASE II RETROFIT

- A. Reheat Finishing Section
- B. Low Temperature Superheat
Pendant Section
- C. Economizer Section

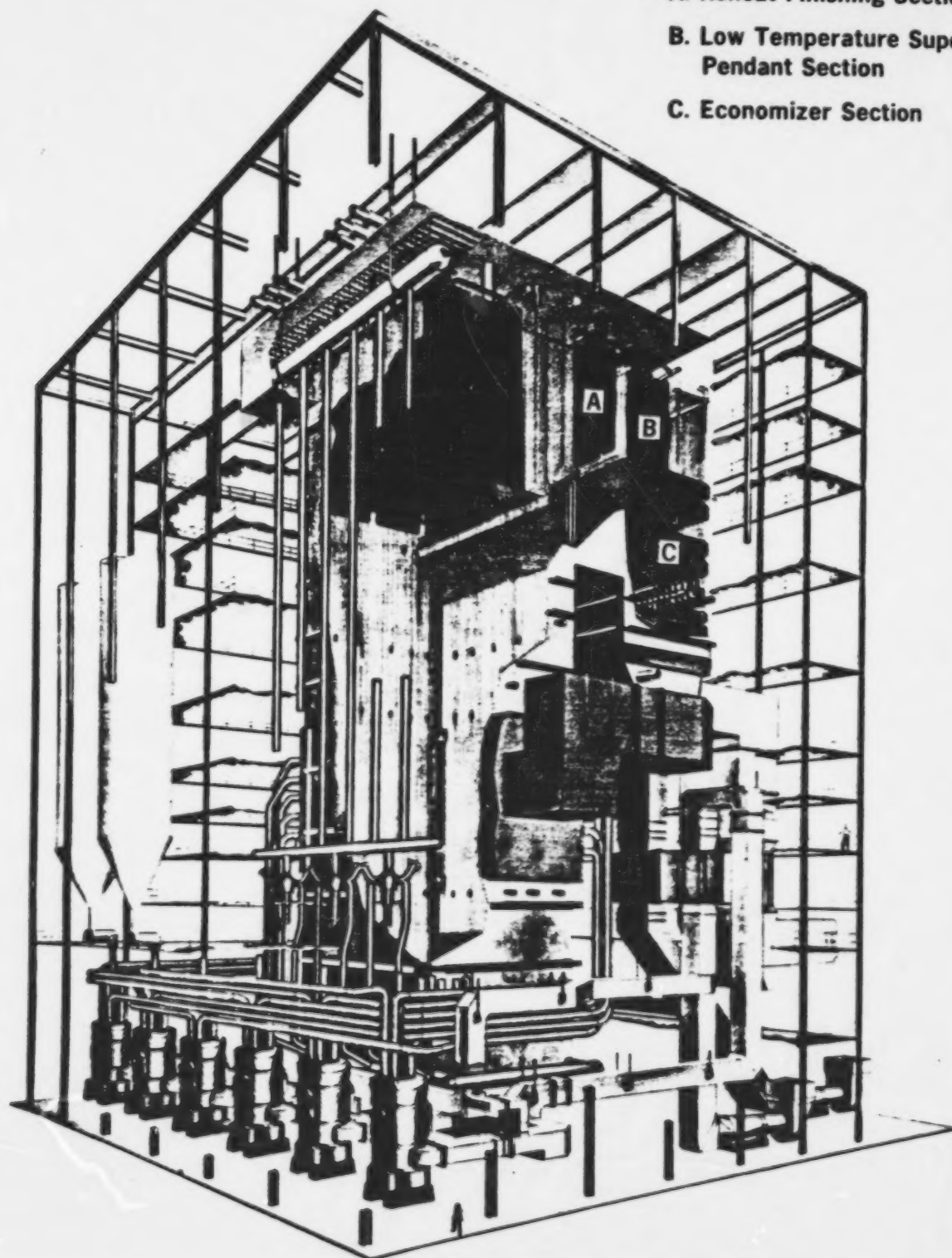
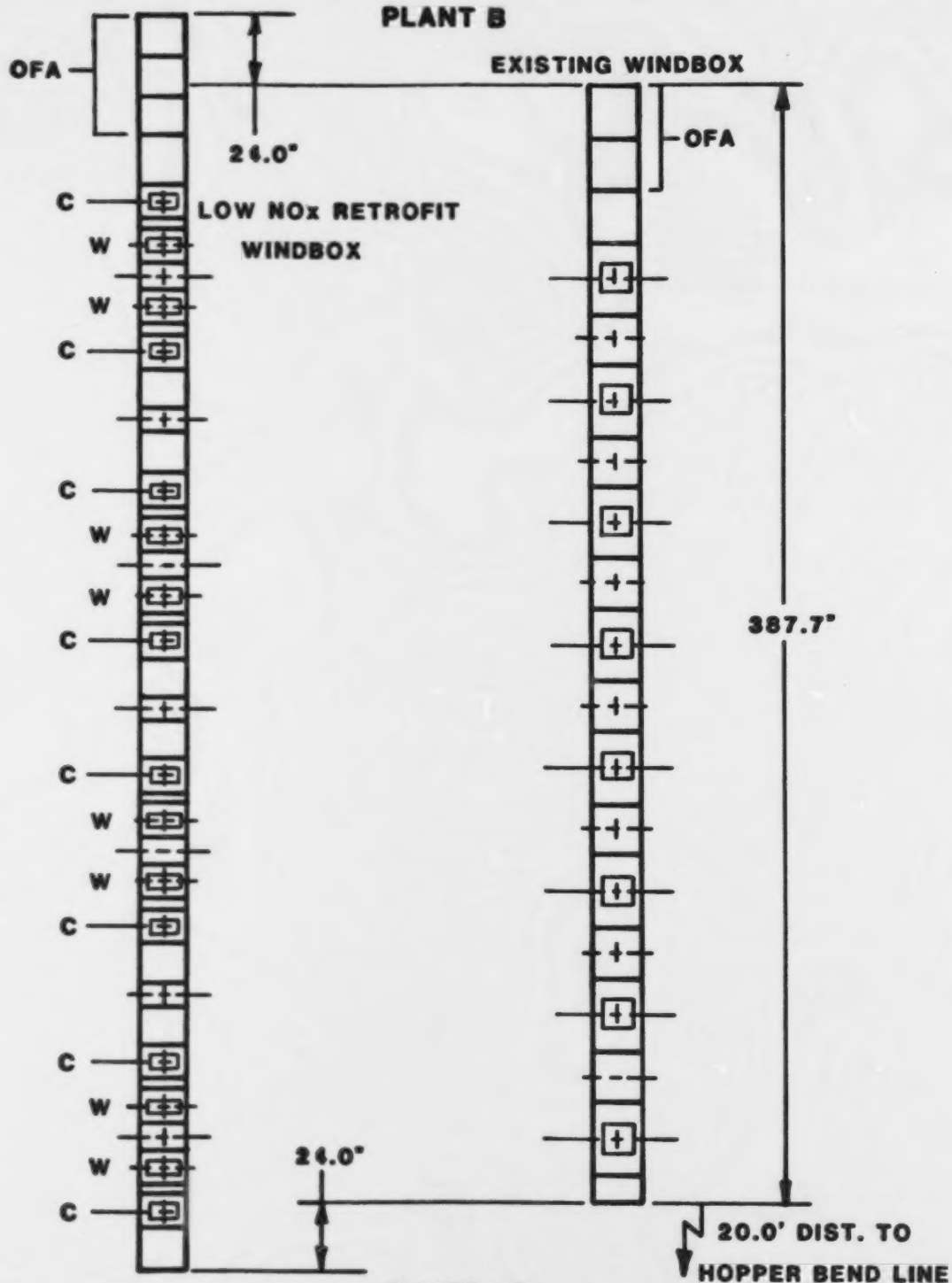


FIGURE #6

RETROFIT LOW NO_x BURNER SYSTEM PLANT B



**HEAT RELEASE ZONES
PLANT B**

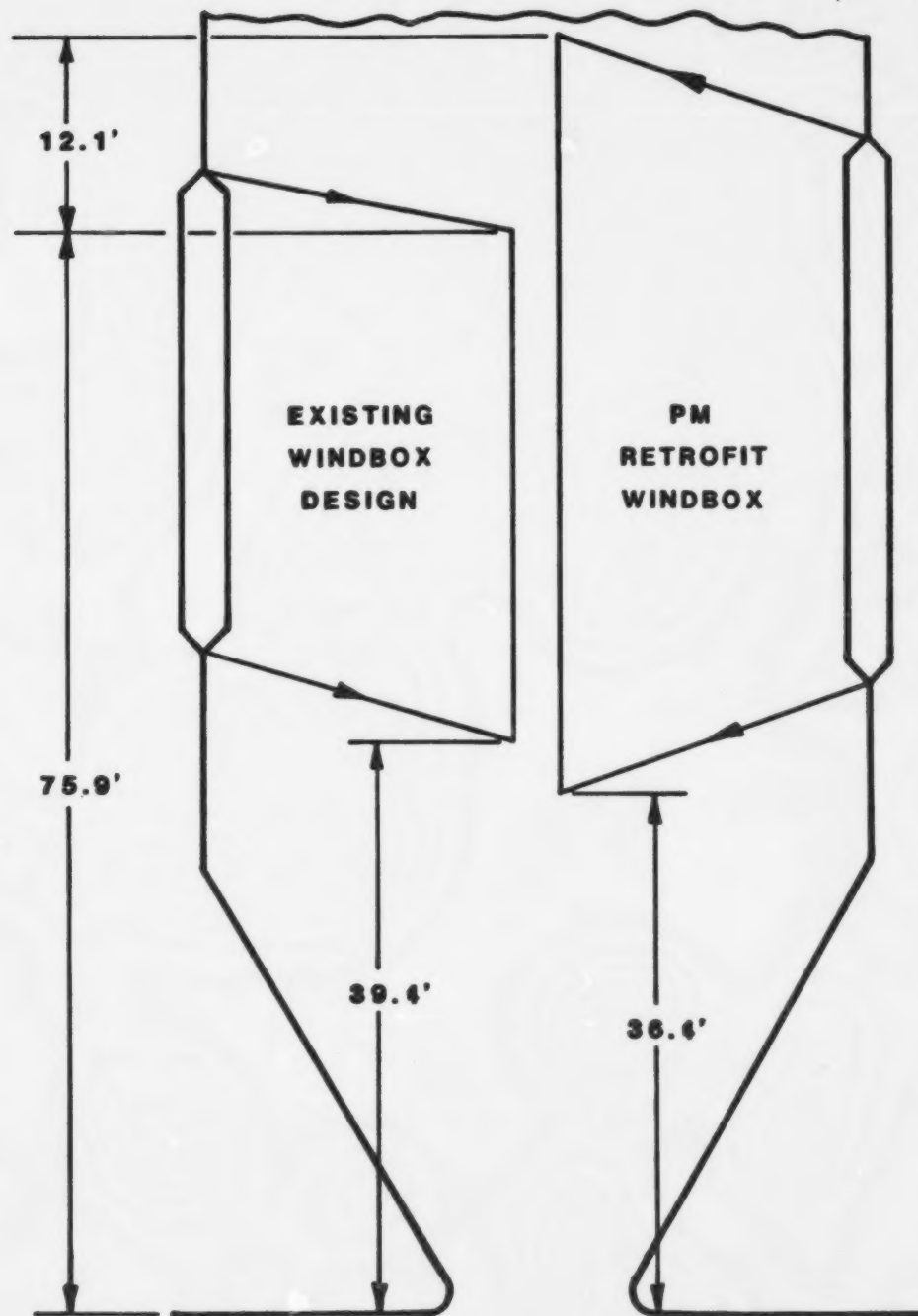


FIGURE #8

TABLE A

PM BURNER

NO_x PERFORMANCE SUMMARY

PLANT A	NO_x GUARANTEE†	% NO_x REDUCTION††
CASE I	190	46
CASE II	150	57
NEW UNIT	150	57
PLANT B	160	50

† CORRECTED TO 3% O₂

†† BASED ON PLANT A EMISSIONS OF 350 PPM - CORR. TO 3% O₂

BASED ON PLANT B EMISSIONS OF 320 PPM - CORR. TO 3% O₂

TABLE B

PM BURNER

ECONOMIC EVALUATION SUMMARY *

PLANT A	TOTAL CAPITAL \$/KW	POWER COSTS MILLS/KW-HR
CASE I	7.91	0.22
CASE II	15.90	0.45
NEW UNIT	5.44	0.15
PLANT B	14.29	0.40

*** 1981 DOLLARS CONFIDENCE LEVELS ± 20%**

LOW NO_x FIRING SYSTEM FOR TANGENTIALLY COAL-FIRED UTILITY BOILERS
- PRELIMINARY TESTING -

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ABSTRACT

A full scale utility demonstration of Combustion Engineering's Low-NO_x Concentric Firing System (LNCFS) is currently being conducted, with EPA sponsorship, at Utah Power & Light's 420 MWe Hunter No. 2 boiler. This paper presents the results of the recently completed baseline and post-modification testing. A preliminary analysis of the results has shown that NO_x emissions can be reduced from baseline emission levels of 460 to 480 ppm (corr. to 3% O₂) and 360 ppm with overfire air to levels of 240 to 260 ppm with overfire air following the LNCFS modification. Additional testing is planned to further optimize the emissions reduction capabilities of the system and to determine the long-term effects of low-NO_x operation on boiler performance.

INTRODUCTION

The advent of federal NO_x emissions regulations for steam generators in 1971 led to the development of various innovations in NO_x reduction techniques. The inherently low-NO_x emissions characteristic of Combustion Engineering's tangential firing system afforded C-E the capability to meet the original EPA regulation level of 0.7 lb/MBtu with only minor operational changes. The NO_x emission level that is currently allowed by the New Source Performance Standards (NSPS), 0.5 lb/MBtu, can be met in most cases with the use of overfire air (OFA) and correct fuel nozzle spacing. In order to achieve the EPA projected goals of commercially available technology capable of emitting only 0.2 to 0.3 lb/MBtu, Combustion Engineering undertook a project to develop a controlled combustion technique capable of meeting these goals. This project is being funded by the EPA under contract 68-02-3655.

The requirements of the low-NO_x firing system are based upon current design practices for tangentially fired utility steam generators and upon information that is currently available with regard to NO_x reduction research. The two general requirements for the low-NO_x firing system are, first, to show that NO_x emissions are reduced as a result of implementing the system and second, to have no adverse effects on the performance of the host steam generator.

NO_x FORMATION

As Levy, et al. stated, "the formation of nitrogen oxides during coal combustion is a complicated process involving contributions both from the fixation of atmospheric nitrogen (thermal NO_x) as well as from the oxidation of nitrogen bound chemically in the fuel (fuel NO_x). The formation of nitric oxide via the thermal fixation of atmospheric nitrogen has been shown to be adequately represented by the highly temperature dependent chemical reaction of the Zeldovich mechanism.(1-4) The rate of formation is exponentially dependent on temperature and is proportional to the square root of oxygen concentration. Both, reducing the amount of oxygen available to the fuel and reducing the combustion temperature, are effective methods of controlling NO_x formation via the thermal mechanism.

Although only a fraction of the fuel nitrogen is converted to NO_x, fuel NO_x can represent a major fraction of the total NO_x formed when firing a high nitrogen content coal in a conventional steam generating unit. In a tangentially fired unit, fuel NO_x accounts for 30 to 55% of the total NO_x emission for the low moisture, high rank coals, and for 50 to 75% of the total NO_x emission for the high moisture, low rank coals.(4) Thus, in pulverized coal firing, fuel nitrogen conversion is an extremely important source for NO_x formation.

Several areas of NO_x formation that are not being accounted for in this study are the coal properties and burning characteristics affecting NO_x. A fuel associated property which can have an indirect but significant effect on thermal NO_x formation in a furnace firing pulverized coal is the coal ash characteristics. Various parameters, including the gravity fractionation and acetic acid soluble measurements along with more conventional base/acid, iron/calcium, silica/alumina ratios and ash fusibility measurements are considered when evaluating the slagging propensity of a particular ash. If the composition and distribution of mineral matter combined with local stoichiometries and gas temperatures results in a sufficiently sintered or molten deposit, the cleanability can suffer causing a significant layer of ash to be formed on the waterwalls. As the deposit builds up, the insulating effect of the ash will reduce waterwall absorption rates, thereby causing an increase in the furnace combustion temperature. As a result, thermal NO_x formation will increase. Changes in furnace wall conditions have been observed to produce 100 ppm differences in the NO_x emission level on a given coal fired unit.(5)

Further, many high iron coals with a potential to deposit ash on the furnace waterwalls in the firing zone must be fired at higher excess air levels to ensure an oxidizing atmosphere thereby raising ash fusion temperatures and minimizing the potential for ash deposits which can lead to corrosion. Consequently, coal ash properties indirectly affect NO_x formation since potential slagging associated with the ash may severely limit and preclude the gross reduction of excess air as a means of limiting NO_x reduction. (Use of a reduced amount of excess air as a NO_x reduction process will be shown later.)(5)

One other fuel property that has a significant effect on NO_x formation is the coal oxygen to coal nitrogen ratio. The oxygen content of coals found in the United States varies significantly. The oxygen content of the low rank Western sub-bituminous coals is three to four times that of the higher rank bituminous coals. Additionally, the nitrogen content decreases only slightly with decreasing rank. Consequently, the coal oxygen-to-nitrogen ratio increases as rank decreases. As a result, the degree of conversion of coal bound nitrogen, in general, increases with decreasing rank.

As a consequence, it is highly conceivable that a lower nitrogen content Western sub-bituminous coal might exhibit a higher fuel NO_x formation level than a higher nitrogen content Eastern bituminous coal would exhibit. Figure 1, which shows fuel NO_x formation as a function of the coal oxygen-to-nitrogen ratio and the coal nitrogen content, illustrates this possibility.

Of specific importance here is the realization that even in a diffusion flame where the combustion air is gradually entrained along the length of the flame, the lower limit of NO_x emission attainable may be controlled by the presence of the oxygen and the nitrogen contained in the coal itself.(6,7) On a tangentially fired unit, the pulverized coal is conveyed from the mills to the furnace in an air-stream with typical air-to-coal ratios of 1.5 to 2.0 pounds of air per pound of coal. Since this stream represents about 15 to 20 percent of the total combustion air, oxygen contained in the coal itself can represent a significant source of oxygen in the early stage of coal devolatilization and combustion. For a high oxygen Western sub-bituminous coal, the coal oxygen can constitute up to a third of the total available oxygen in the mill air/pulverized coal stream. Additionally, the coal bound oxygen is in more intimate contact to the coal bound nitrogen.

The next step in determining the most effective method of lowering NO_x by optimizing combustion conditions is to relate how these parameters^x affect the NO_x formation process. It is recognized that combustion of the bulk of the pulverized coal particles occurs in three main stages: evolution of the coal's volatile components (devolatilization), followed by homogeneous volatile combustion, and finally, heterogeneous combustion of the residual char. Although the stages may overlap it is clear that char combustion is generally of much longer duration than volatile combustion. (Very fine coal particles can begin to burn heterogeneously in the early stages during the evolution of the volatile matter. Refer to figure 2.) Based on this model, the conversion of coal-nitrogen to NO_x can, therefore, also be regarded as a three-stage process: coal-nitrogen devolatilization, volatile-nitrogen combustion, and char-nitrogen combustion. It is evident that the extent of devolatilization prior to ignition and the distribution of nitrogen between char and volatiles will strongly influence NO_x emissions.(8) (See figure 3)

Studies conducted prior to 1977(9,10,11,12) relating the distribution of coal nitrogen between volatiles and char during pyrolysis and oxidation were usually limited to fluidized-bed and coking conditions with temperatures below 1750°F. More recent work by Levy, Pohl, Sarofim, and Song (1978)

at pulverized coal firing conditions, higher temperatures, longer residence times, particle reactions, and higher heating rates, has led to the conclusion that much of the fuel nitrogen may be devolatilized at these higher temperatures. This result was contrary to extrapolation of data conducted previously using fluidized-bed combustors. These new results, taken independently, do not have much bearing on the reduction of NO_x emissions because fuel NO_x has been shown to be fairly independent of temperature. However, they have led to research into studies relating to the delayed introduction of combustion air (staged firing) as a NO_x reduction mechanism.

The NO_x reduction strategy that Levy, et al. (1978) have developed for a single stage combustor is to increase the fuel/air ratio to the limit imposed by the emission of unburned carbon, CO, or soot. In a staged combustor, the strategy for decreasing the conversion of fuel nitrogen to nitric oxide is to increase the fuel/air ratio initially which results in decreases in conversion efficiency of the fuel nitrogen to nitric oxide for the nitrogen content of the volatiles. Since char oxidation is slow and nitrogen retained in the char may be oxidized to nitric oxide in a second stage, it is advantageous to operate the first stage at high temperatures to devolatilize the coal nitrogen in the locally fuel rich environment. The second stage should be fuel lean and at a low temperature (keeping excess air to the smallest amount possible without creating excessive carbon losses). The staging can, of course, be achieved either by introduction of the combustion air at different positions in a furnace or by aerodynamic means.

Another study in which NO_x reduction mechanisms were researched using pulverized coal firing conditions is titled Burner Criteria for NO_x Control, authored by Heap, et al. (1976). (13) They studied various flame processing techniques to determine the optimum firing conditions for the reduction of NO_x including the staging of combustion air as stated above.

The first priority would be to minimize the amount of primary air contained in the coal jet. (The optimum amount of primary air was experimentally determined to be approximately 20% of the stoichiometric requirements.) Next, it would be desirable to stabilize the ignition front as close to the injector as possible. This is desired because the presence of the ignition front and the associated heat release acts as a driving force to remove the volatile bound nitrogen from the coal particle and a close ignition point will maximize the release of the volatile nitrogen in a fuel rich atmosphere. Whereas, without a stable ignition front, additional oxygen may be entrained in the fuel jet resulting in higher NO_x .

It can be seen that many of the conditions that tend to provide the high intensity combustion and rapid burnout desired for practical systems also produce high NO_x emissions. Stated next are the requirements for NO_x reduction that have been deemed to be applicable to a burner modification of a practical system.

The low- NO_x firing system should not increase emissions of other pollutants such as CO, unburned hydrocarbons (UHC), and unburned carbon in the particulate matter contained in the flue gas and bottom ash. This is a

requirement pertaining to system efficiency; for if the amounts of CO, UHC, and/or carbon present in the particulate matter or ash increase, then the firing process is not being completed and a potential heat source is being lost to the bottom ash hopper and to the precipitators.

There should be no increase in slagging with the use of the low-NO_x firing system for this would lead to an increase in the use of soot blowers, and a decrease in availability dictated by a boiler turndown in the event that load dropping became necessary as a slag shedding procedure. Increasing soot blowing activity requires an increase in chemically treated boiler make-up water, thus increasing production costs. Increased accumulation of slag on the waterwalls could also have a detrimental effect on the heat transfer rate to the waterwalls. This increase of slag results in decreased lower furnace heat transfer due to the insulating effect of the slag, thus the gas temperature entering the convective heat transfer section of the unit increases thereby raising the final superheat and reheat temperatures. This condition requires the use of more desuperheat spray to be used as a temperature controlling mechanism. Also, if the gas temperature is greater than the fusion temperature of the ash constituents of the coal being burned, an increase in fouling and plugging in the convective section can occur. Normal boiler operating practice in situations such as this requires a reduction of boiler load to shed slag, thus increasing the operating costs of the unit.

The percentage of excess air used should not be increased because NO_x emissions would increase (this result is shown in Figure 4). Also, this would increase the sensible heat loss via the flue gas exiting the furnace. This would result in lower boiler efficiencies. An increase in the amount of excess air used will also increase the gas velocities in the superheater, reheater, economizer, and air preheater sections of the boiler which will cause erosion due to the presence of flyash. Increasing the percentage of excess air can produce flame instability which will decrease the turndown capability of the boiler unit. This will result in the use of higher priced auxiliary fuels during low boiler load operating conditions to provide ignition stability.

The primary air/coal velocities should not be decreased as this could cause an increase in coal drop-out in the primary air/fuel feed pipes. This decrease in velocity will bring the ignition point closer to the coal injector which is good for NO_x reduction, however, it could also cause increased coking and coal nozzle deterioration.

The low-NO_x firing system modification to the windbox should not have a detrimental effect on flame stability in general and at low loads in particular as this will decrease system availability.

The system should be designed in such a way so that "hotspots" do not occur on the waterwall (due to flame impingement) as this may cause running slag. Hotspots may also cause tube failures due to a departure from nucleate boiling.

Any modifications to the system should take into account the capacity of the forced draft (FD) fan. The low-NO_x firing system should not induce

a pressure drop which the FD fan cannot accommodate as this will affect unit availability or it would necessitate a capital expenditure and an increase in operating costs to handle the increased pressure drop.

The design of the low-NO_x firing system shall be such that during boiler operation the flame front is close enough to the coal nozzle so that a correct interpretation of flame presence by the flame scanner is possible.

Any modifications to the windbox to implement the low-NO_x firing system should not have any adverse effects upon the burner tilt mechanism.

Any modifications that are required to implement the low-NO_x firing system shall be sound in structure, shall fit into the required confines of the windbox, and shall not have any extraneous hardware exposed to the furnace environs.

The low-NO_x firing system should be designed in such a fashion as to restrain the mixing between the primary air/coal and the secondary air. This design is desirable because it reduces the amount of NO_x formed via two mechanisms. First, by having a fuel-rich/air-lean atmosphere during the coal firing process, the initial amount of NO_x formed is reduced because less oxygen is available to combine with fuel nitrogen. Second, because of the reduced air concentrations during the initial stages of the firing process, primary stage residence time increases. This increased residence period provides an environment which is desirable for the reduction of any oxidizable N₂ intermediates that have been formed (such as NH₃ or HCN). This is done by entraining and reducing NO_x compounds and the intermediates into their elemental components, oxygen, nitrogen, hydrogen, carbon, and combusting the hydrocarbons.

The boiler modification should differentiate the fuel rich and air rich sections of the boiler and for each burner level of each windbox. The ignition front of each fuel nozzle should be fuel rich so that the fuel nitrogen can be driven off from the parent fuel and reduced to molecular nitrogen and oxidizable nitrogen intermediates. The latter stages of the combustion process should be air rich to assure complete combustion and to preferentially react the nitrogen intermediates formed during the first stages of combustion with the excess oxygen and the NO formed during char combustion. This will further reduce the flue gas NO_x emissions level.

LOW-NO_x CONCENTRIC FIRING SYSTEM (LNCFS) - SYSTEM DESCRIPTION

The low-NO_x concentric firing system was developed for applications in tangentially fired steam generators. The system is designed to limit NO_x emissions by aerodynamically controlling the mixing of the fuel and the combustion air. The aerodynamic control is achieved by directing the auxiliary air (so called because it flows through the auxiliary compartments located between successive fuel elevations in a windbox ...see figure 5 for a typical windbox arrangement) towards an imaginary circle that has a larger radius than the firing circle which is typical to tangential firing (see figure 6). With this type of configuration the flame front is stabilized and the initial coal devolatilization period

occurs with a fuel rich atmosphere. Also, during the design of this system it was felt that the decrease in the fuel and air jet momentum directed towards the firing circle would allow the flame front to be stabilized at a point closer to the burner. This would further lengthen the fuel rich zone during which fuel bound nitrogen could evolve and be reduced to N_2 . However, as will be discussed later, in the full scale demonstration tests this was not seen simply with the horizontally offset firing design. A closer stabilized flame front was observed in the second generation of the LNCFS which included flame holders (or flame diffusers as they are sometimes called) on the coal nozzle tips.

The velocity of the secondary air (secondary air is composed of the auxiliary air, fuel compartment air that flows around the fuel pipe and nozzle tip, and overfire air (OFA)) was increased in the design of the LNCFS to prevent the premature reentrainment of the offset auxiliary air with the primary air, fuel, and fuel air.

The remainder of secondary air, that which is not used to stabilize the flame front (fuel air), and that which is not directed towards the waterwalls in the offset firing mode (auxiliary air), is injected into the furnace proper through the overfire air compartments. This completes the staging process and assures a high carbon conversion rate.

LARGE SCALE UTILITY DEMONSTRATION TEST - UNIT DESCRIPTION

After the successful completion of several laboratory scale tests of the LNCFS design and a pilot scale test at a 65 MWe municipal utility unit, C-E was contracted by the EPA to convert a full scale utility boiler to this design to determine the full scale NO_x reduction capabilities of the system and to assess long-term low- NO_x operating conditions with regards to waterwall corrosion and boiler efficiency. The Hunter No. 2 unit of Utah Power & Light Co. was chosen as a host utility for this demonstration test (see Table I for fuel, firing system and furnace information).

The modification to the unit consisted solely of windbox components, and in particular, the coal and auxiliary compartments (figures 7 and 8). The three main auxiliary compartment elevations and the two half-size and auxiliary compartments were modified to accept horizontally adjustable offset air nozzle tips (figure 9). The coal compartments were modified by reducing the free area available through which fuel air could pass. This forces more air (represents a reduction of approximately 40% in full load fuel air) through the offset auxiliary compartments and the two unmodified overfire air compartments. This was done by removing the two fuel air nozzle tips located in each coal compartment and blocking off a majority of the free area. The remainder of the fuel air free area was incorporated into a single slightly larger coal nozzle tip. The bluff body created by the blocking off of this free area enhances recirculation of the fuel rich primary airstream and thus helps to create a close stable flame front.

Following the March 1982 series of post-modification testing, it was decided that a further optimization of the LNCFS was necessary to stabilize

the flame front even closer to the coal nozzle tip than had been possible with the bluff body created with the original LNCFS design. This goal was accomplished by directing the fuel air away from the primary air and fuel jet with a divergent coal nozzle tip (flame holder).

DISCUSSION OF TEST RESULTS

Under this test program four series of testing have been conducted. Variables such as excess air, burner tilt, overfire air amount, overfire air tilt, and fuel compartment/auxiliary air compartment air flow distribution and their relation to NO_x emissions were tested independently and together to characterize the operations and emissions of the unit. The first series, baseline testing, was conducted prior to the unit modification during August, 1981. The second series, post-modification I, primarily examined the effects of burner tilt, offset angle, and fuel compartment/auxiliary air compartment air flow distribution without overfire air. These tests were conducted during November, 1981. The third series, post-modification II, was conducted during March, 1982. The primary emphasis for this phase of testing was to determine the combined effects of the offset firing system with overfire air and overfire air tilts on NO_x and boiler performance. The fourth series, post-modification III, was performed during September, 1982. There were two purposes for these tests: first, to determine the effects of the flame holders on unit performance and emissions and second, to operate the boiler for a three day period using the long-term operating procedure as proposed following the March, 1982 tests and optimized for the flame holders during this, the fourth series, testing.

Baseline Testing (August, 1981)

A total of 64 tests were conducted between August 3 and August 18, 1981. The normal operating conditions for the parameters thought to be significant in NO_x reduction strategies and the range for which they were tested are listed in Table II. NO_x emission levels for the standard operating conditions (4.5% O_2 , no OFA , and horizontal burner tilts) were approximately 460 ppm (adjusted to 3% O_2) and are shown in figures 10 and 11. Analysis of the results from test series which dealt with each operating condition independently yielded the following conclusions:

- o Variations in the excess air level (measured and reported as flue gas oxygen level) result in a linear change in the flue gas NO_x emissions level (see figure 11). A one percent decrease (or increase) in the oxygen level lowers (or raises, respectively) the NO_x concentration by approximately 45 ppm. This linear relationship existed for the entire test range (2.4% to 5.8% oxygen).
- o The use of overfire air (OFA) will reduce NO_x emissions by about 70 ppm when the OFA tilt is horizontal (see figures 11 and 12) and by approximately 100 ppm when the OFA tilt is set to +30 degrees.

- o Overfire air uptilt will improve the NO_x reduction capability of OFA by about 30 ppm when changed from horizontal to plus thirty (+30) degrees (compare figures 13 and 14).
- o A reduction in the amount of fuel air (fuel compartment secondary air) resulting from the closure of the fuel air dampers from 100% to 50% yields NO_x reductions of approximately 50 to 60 ppm.
- o The results from the burner tilt variation tests were inconclusive with respect to NO_x emissions. However, the few tests that were run yield a trend of increasing NO_x (about 30 ppm) with increasing burner tilt (from -10° to +10°) (see figure 13).

During the tests which combined the extremes of several or all of the NO_x reduction strategies it was shown that the NO_x reductions are additive. However, operating under these combined NO_x reduction strategies was not deemed acceptable from an operations standpoint.

For the baseline tests the lowest NO_x level achieved with acceptable boiler operations was approximately 300 ppm NO_x (adj. to 3% O₂). It should be noted that there were three (3) tests during the baseline characterization which had NO_x levels below 300 ppm (adj. to 3% O₂), however they were not included because of unacceptable boiler operations. In two of the tests a large oxygen unbalance was present and a relatively high flue gas CO level was also present. A third test reported 302 ppm NO_x which was more in line with the NO_x vs. O₂ trends seen in figure 12.

Post-Modification Testing (November, 1981, March and September, 1982)

These three series represent a total of 233 individual tests. Of these, 94 were conducted without overfire air, 17 with partial overfire air, and the remaining 122 tests were conducted with full overfire air. Analyses of the results from these tests were used to determine the optimum windbox and operational arrangement for the long term emissions and waterwall tube corrosion assessment.

All results presented in this paper are for tests which reported less than 100 ppm CO (carbon monoxide). Tests were conducted which reported higher CO levels, however, they have not been included because they do not present acceptable operating conditions in terms of unit efficiency. Tests which produce high carbon monoxide levels may have been conducted while operating under any of the many anomalous conditions which produce low-NO_x at the expense of boiler efficiency. Results have been presented in graphical form in figures 10 thru 16. A few of the key conclusions have been summarized below.

- o Full load NO_x levels of between 230 ppm and 260 ppm (adjusted to 3% O₂) were demonstrated without adverse effects on unit performance. These levels have been shown in both the short term controlled characterization tests and in the long term operations assessment program.

- o The unit can and does operate efficiently with an average flue gas oxygen level of between 3.5 and 4.0 percent oxygen. Operating with a lower excess air setpoint has allowed the utility to lessen its sensible heat loss in the flue gas in addition to lowering its baseline NO_x emissions level by approximately 45 ppm, with no adverse effects on slagging.
- o The full load NO_x reduction potential of the second generation Low-NO_x Concentric Firing System (LNCFS with flame diffusers) is approximately 80 ppm when operating either with or without overfire air (shown in figures 12 and 11, respectively).
- o The partial load NO_x reduction potential of the LNCFS system is dependent upon the number and location of the fuel elevations in service. However, based on the limited number of both baseline and post-modification reduced load tests with either all elevations in service or with only the top four in service, NO_x reductions of approximately 30 to 40 ppm are possible with the low-NO_x system (figure 15). The normal operating procedure for windbox airflow distribution will diminish the NO_x reduction potential of the LNCFS system as unit load is reduced. This is due to the reduction in airflow through the offset auxiliary compartments and the overfire air compartments at reduced load.
- o The trend of increasing NO_x with increasing burner uptilt that was seen in the baseline characterization was repeated with the low-NO_x system. For tests which were conducted with greater than 60 percent overfire air and excess air levels between 3.5 and 4.5 percent oxygen, an increase in NO_x emissions of approximately 75 ppm was shown when burner tilts were raised from minus 10° to plus 20° (see figure 13).
- o The effect of overfire air tilt on NO_x emissions is much more prominent in the baseline characterization (approximately 30 ppm for a 15° difference in overfire air tilt) than in the post-modification characterization (negligible difference). This can be seen by comparing figures 13 and 14.
- o Initial trends comparing baseline and post-modification carbon-in-flyash levels (figure 16) have shown that the NO_x reductions achieved with the low-NO_x system are not at the expense of decreased unit performance.

The Low-NO_x Concentric Firing System with flame diffusers has demonstrated that NO_x emissions can be significantly reduced in tangentially fired systems. Additionally, based on other field work, it has been shown that the system is easily retrofittable to many tangentially fired boilers.

Future work involving a long term operational assessment and waterwall corrosion test is scheduled for 1983 and should further quantify the system NO_x reduction potential and effects on boiler operation.

ACKNOWLEDGEMENTS

The success of this program is due, in large part, to the assistance and cooperation of the engineering staff and operating personnel of Utah Power & Light Company, Hunter Unit 2. We would also like to acknowledge the technical guidance of D. G. Lachapelle, the EPA Project Officer.

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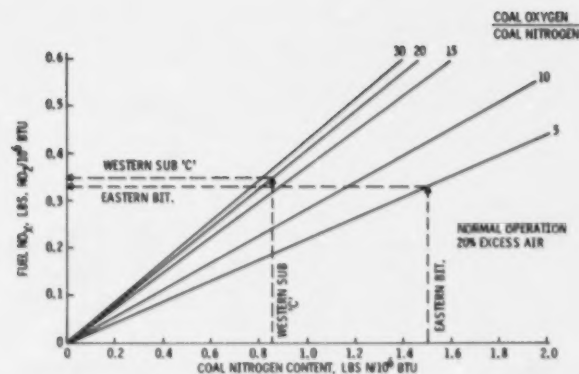


Fig. 1: Fuel NO_x Formation as a Function of the Coal Oxygen-to-Nitrogen Ratio and the Coal Nitrogen Content

CHRONOLOGY OF THE COMBUSTION PROCESS

HEATING AND MINOR DEVOLATILIZATION



IGNITION



MAJOR DEVOLATILIZATION



BURNING OF THE CARBON RESIDUE



0 ————— 1
TIME, SECONDS

Fig. 2

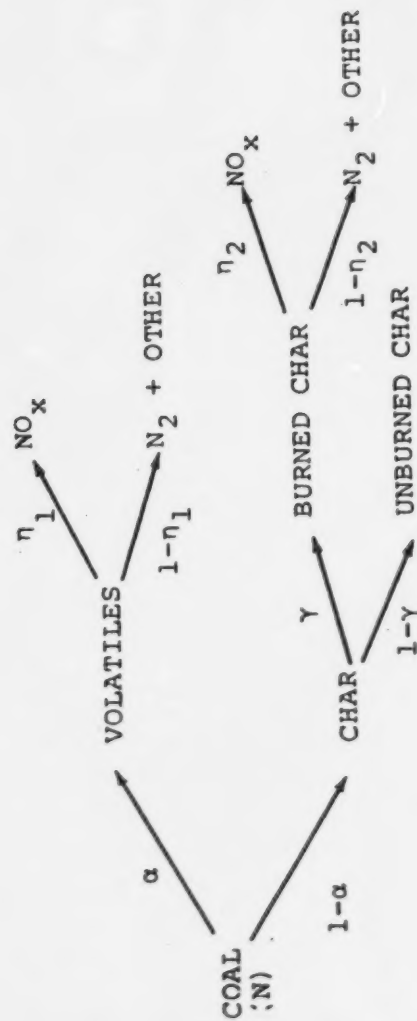


Fig. 3: Evolution of coal-nitrogen during the firing process

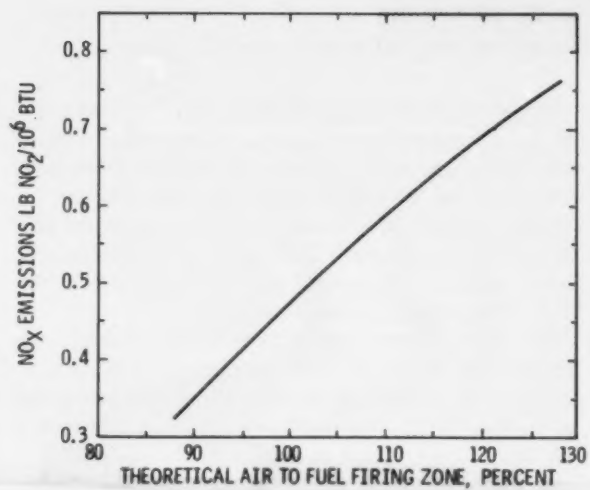


Fig. 4: Decreasing theoretical air to fuel firing zone decreases NO_x emissions

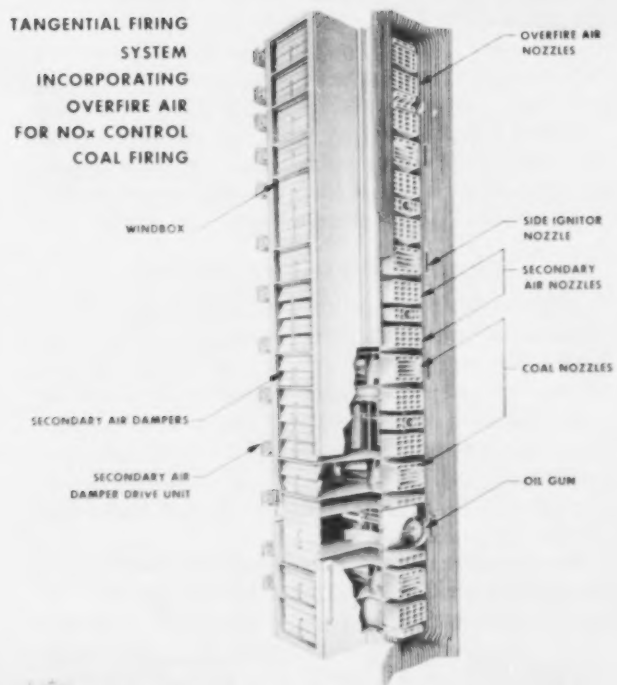


Fig. 5 : Typical Corner Windbox Showing Overfire Air System

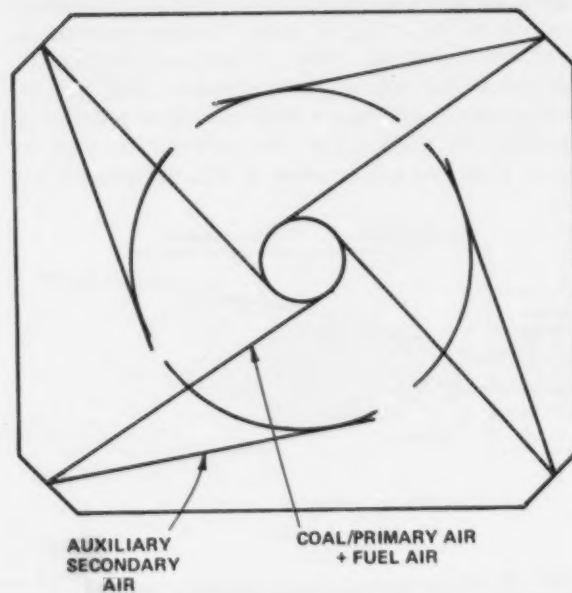


Fig. 6 : Principle of Offset Firing with LNCFS

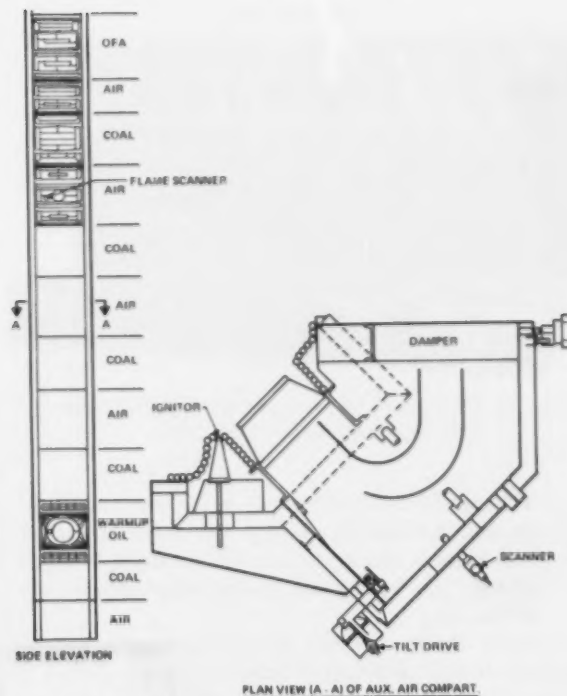
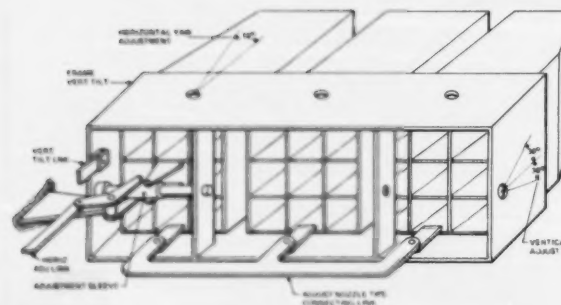
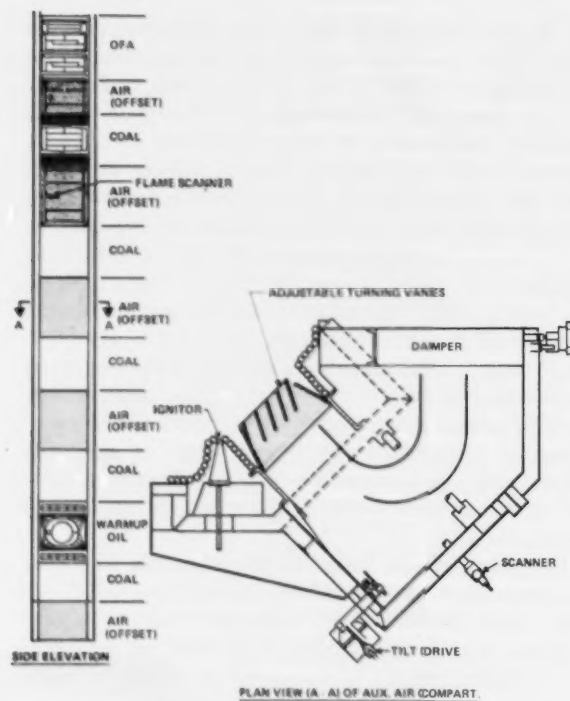


Fig. 7 : Original windbox at Hunter 2



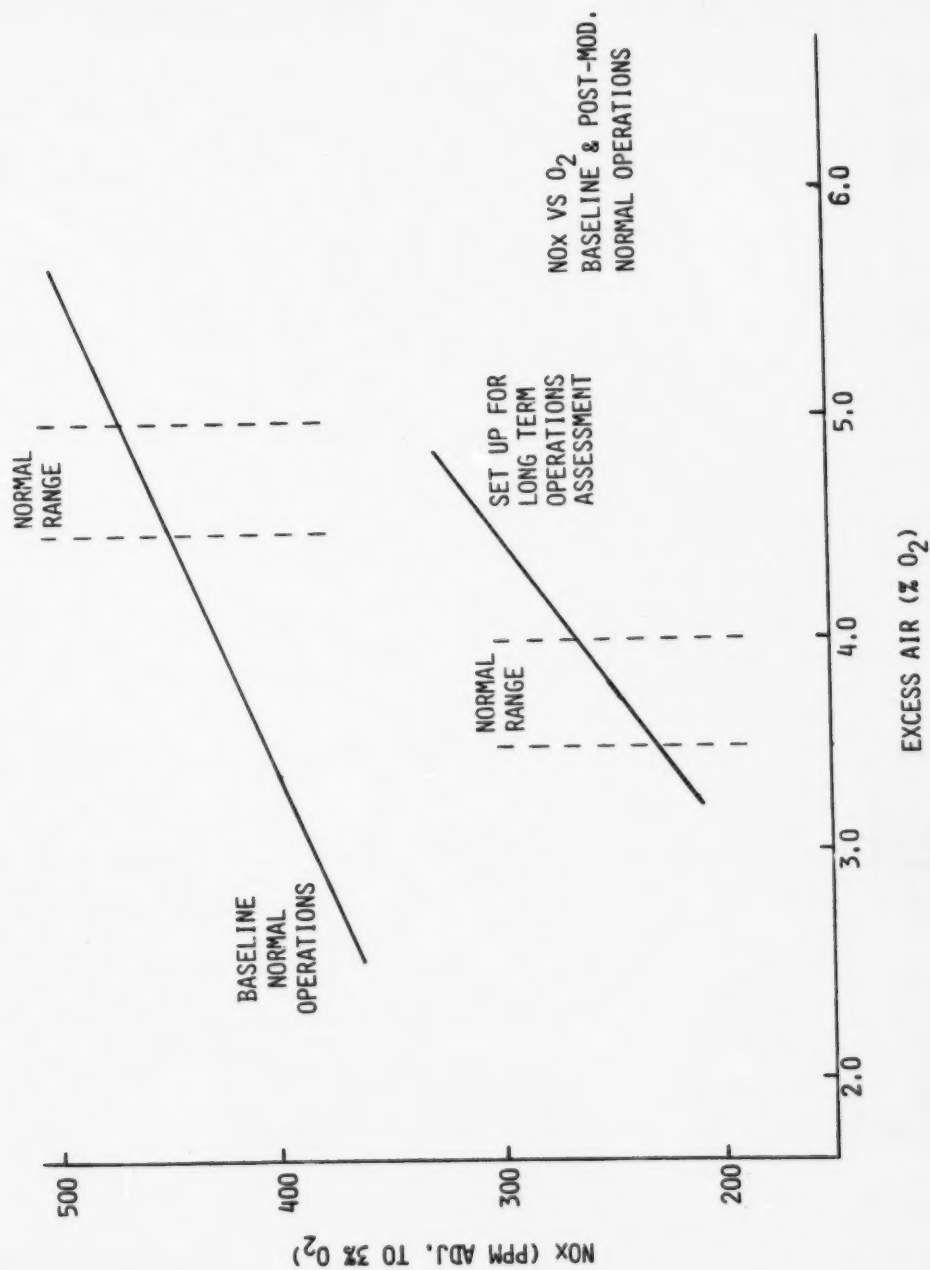


Fig. 10: NO_x versus Excess air - Baseline, Post-Modification and Long Term Operations

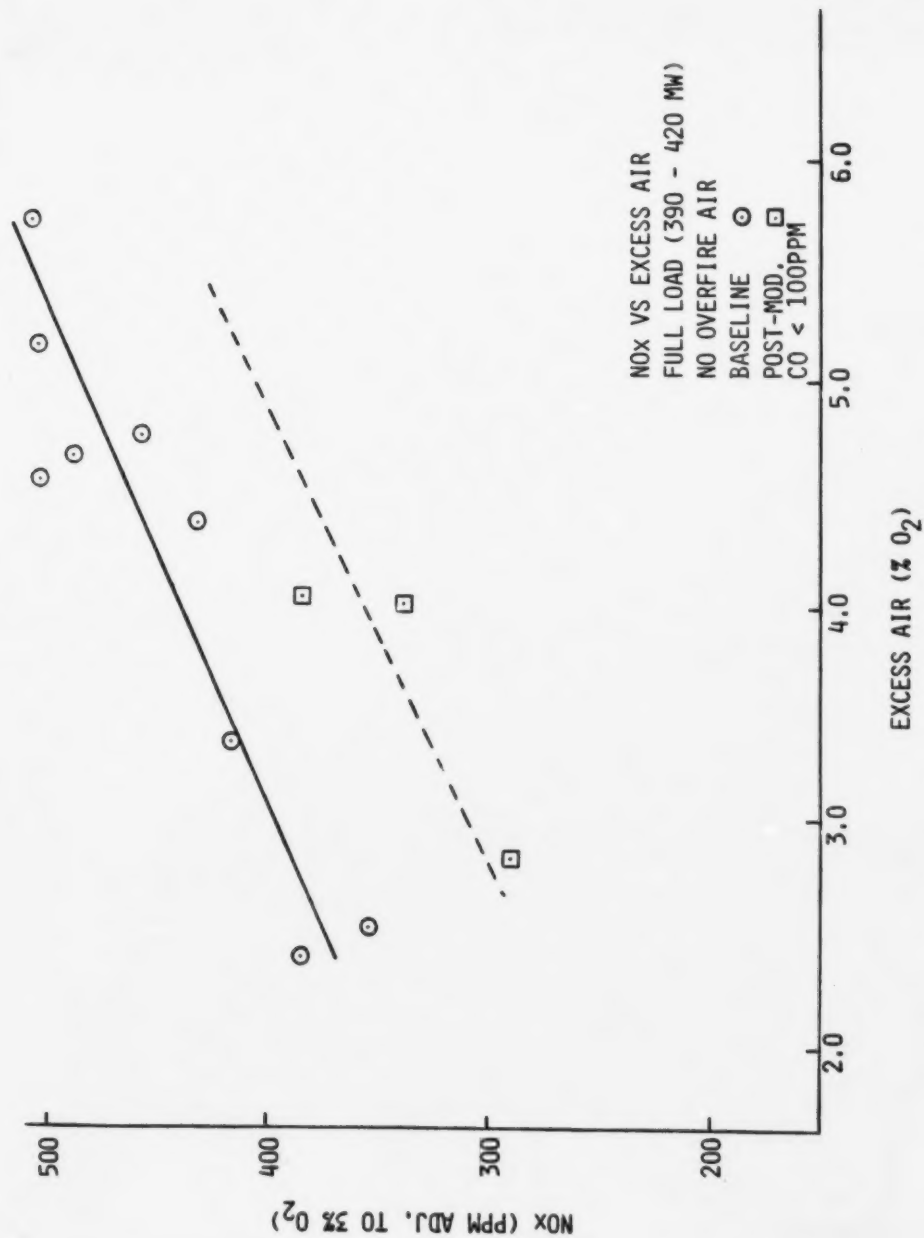


Fig. 11: NOx versus Excess Air - Full Load, No Overfire Air; a Comparison of Baseline and Post-modification Results

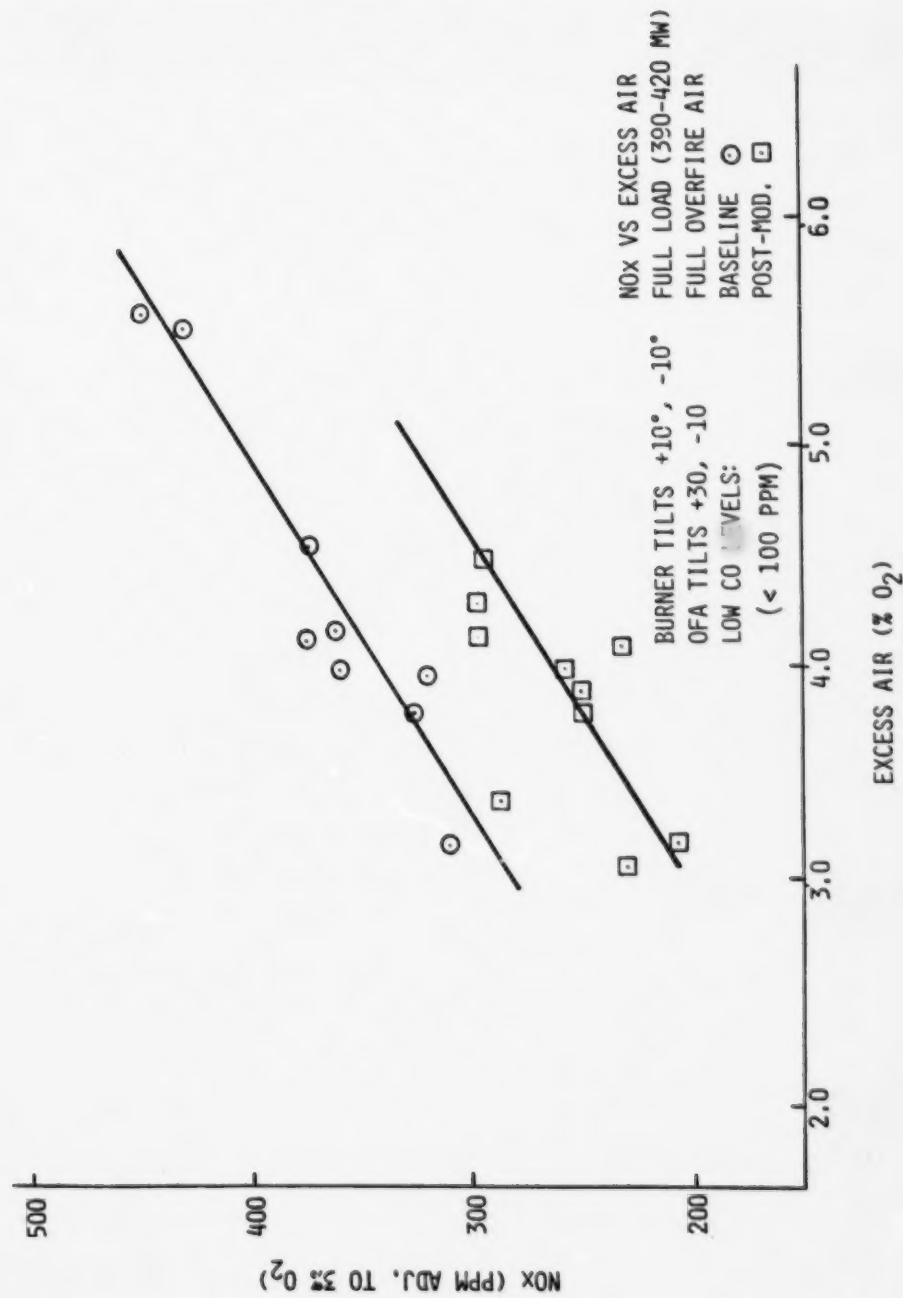


Fig. 12: NOx versus Excess Air - Full Load, Full Overfire Air

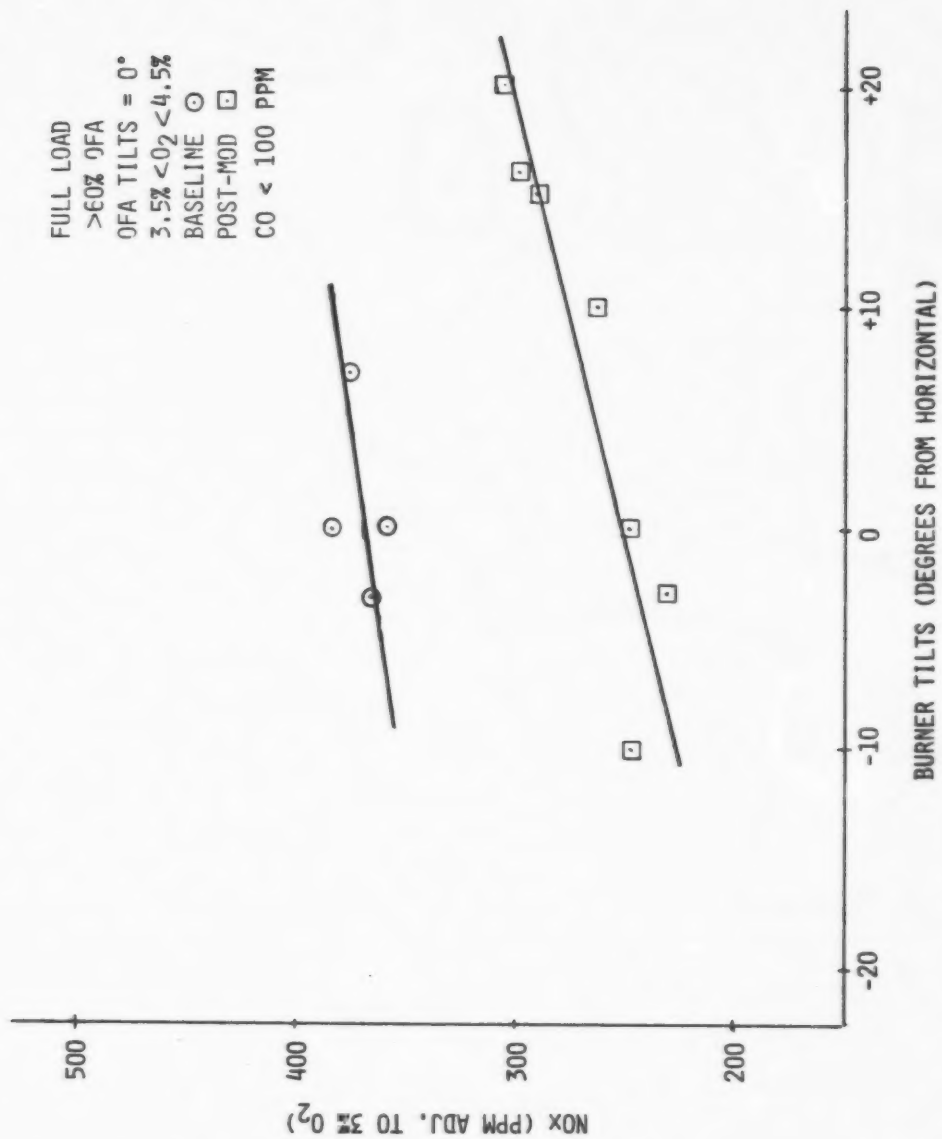


Fig. 13: NOx versus Burner Tilts - Horizontal Overfire Air Tilts

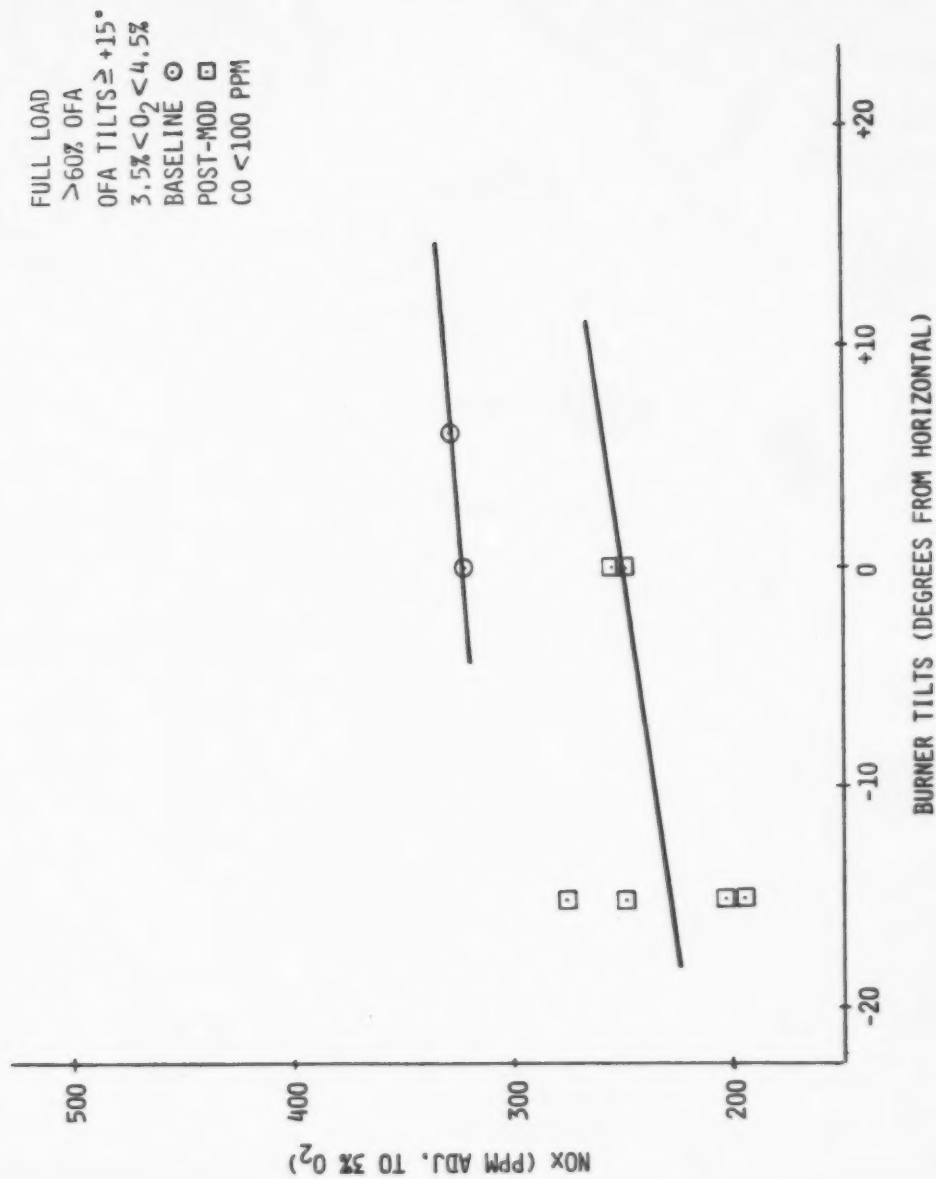


Fig. 14: NOx versus Burner Tilts - Overfire Air Tilts Up

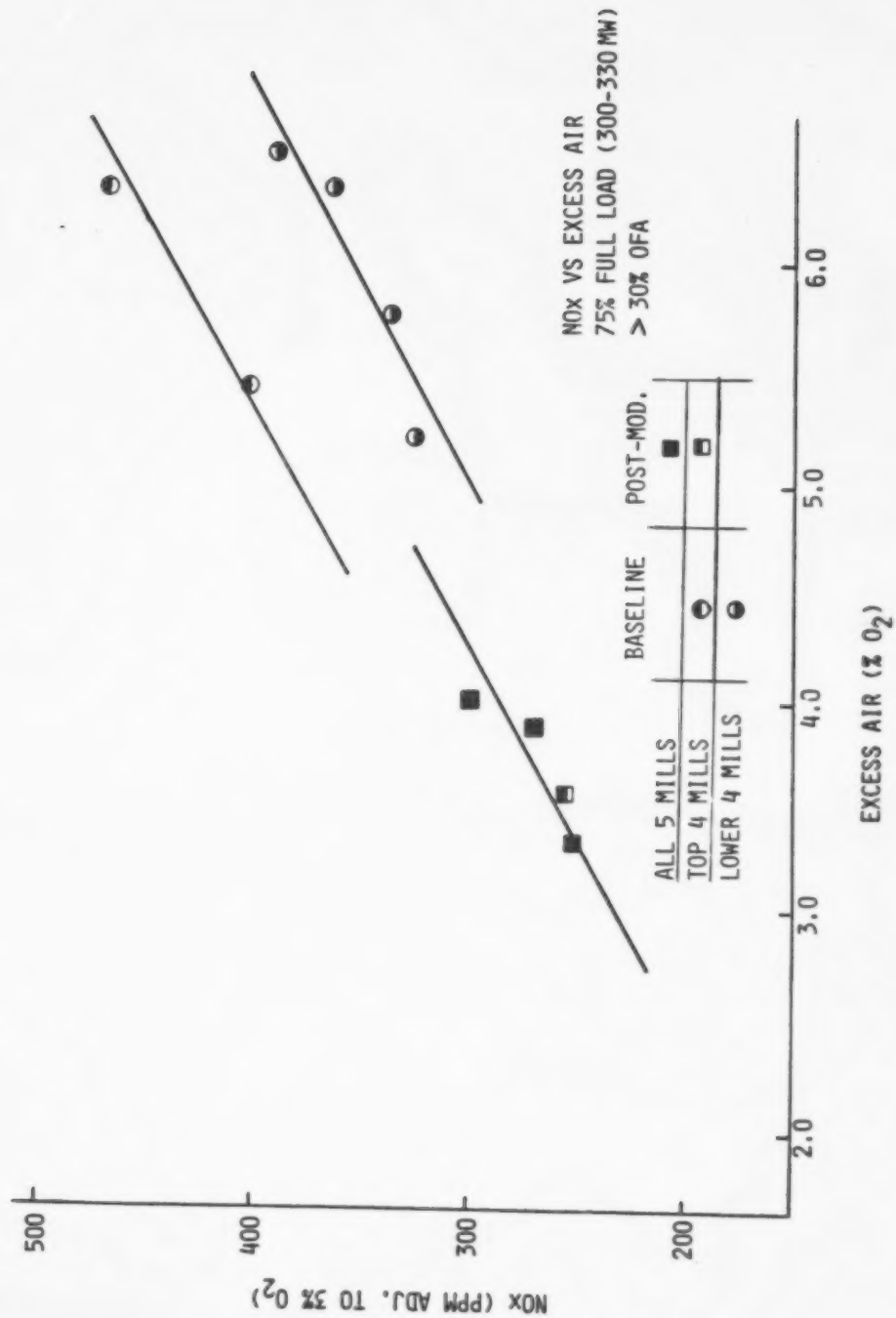


Fig. 15: NOx versus Excess Air - Reduced Load with Overfire Air

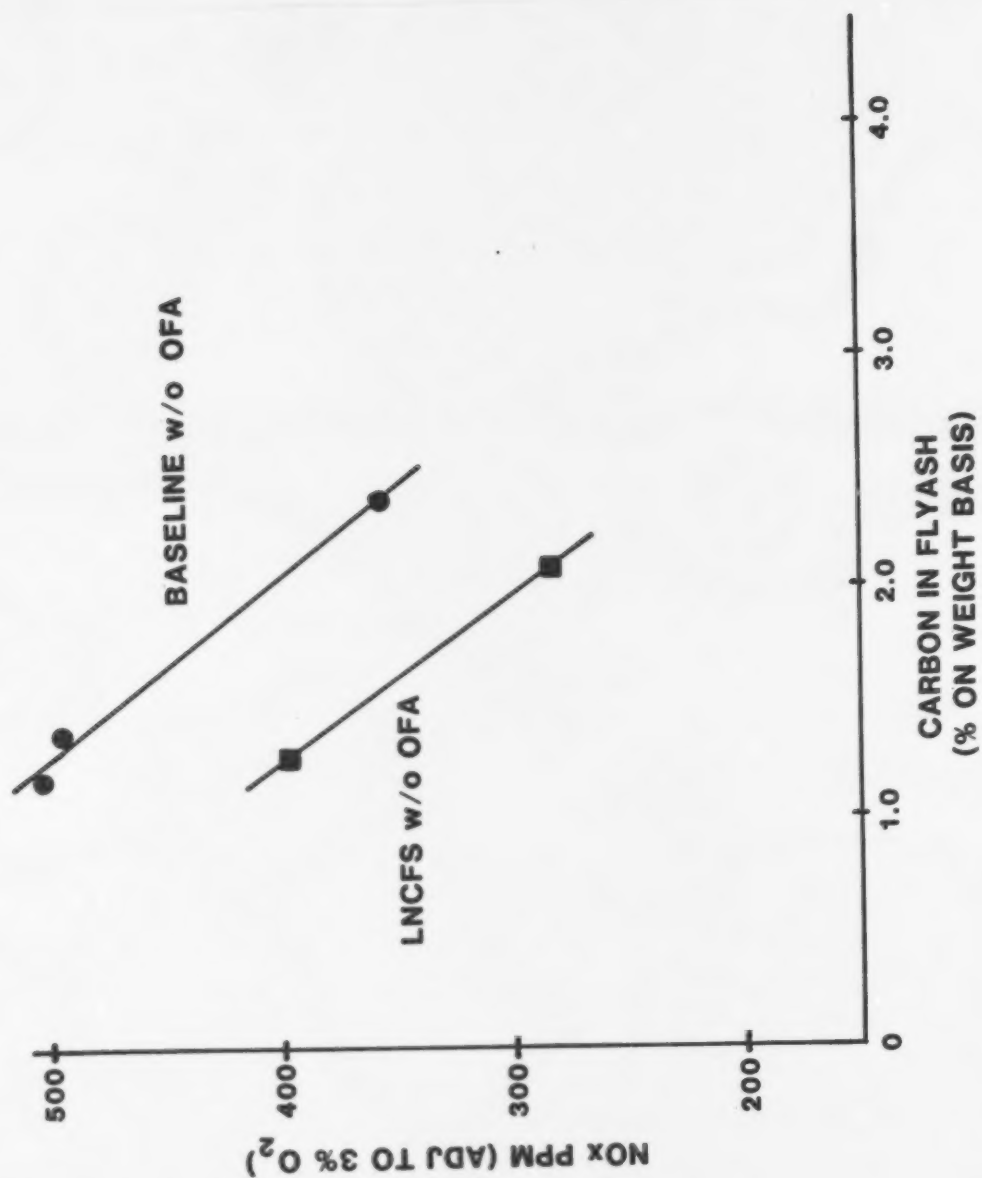


Fig. 16 : NOx versus Carbon-in-Flyash

TABLE I
UTAH POWER & LIGHT COMPANY
HUNTER NO. 2 UNIT

Generator Rating	400 MW	
Maximum Steam Flow	3,036,000 lb/hr	
Maximum Heat Input	4,174 x 10 ⁶ Btu/hr	
Secondary Air Flow	26,350 CFS	
Secondary Air Temperature ...	525°F	
Furnace Width	51'-8"	
Furnace Depth	44'-2 1/4"	
Pulverizers	Five 843 RS (with exhausters)	
Fuel: Mid-western high-vol. bituminous "B"		
Moisture	2.3%, by wt.	
Volatile Matter	39.6%	
Fixed Carbon	46.2%	
Ash	11.9%	
Moisture	2.3%	Ash Fusion Temperatures (Reducing Atmosphere): I.D. 2250°F S.T. 2310°F F.T. 2450°F
H	5.1%	
C	69.6%	
S	1.1%	
N	1.3%	
O	9.3%	
Ash	11.9%	
HHV	12,420 Btu/lb	

TABLE II
BASELINE OPERATING PARAMETERS
NORMAL AND TEST RANGE
FULL LOAD OPERATION

<u>Parameter</u>	<u>Normal Set Point</u>	<u>Test Range</u>
1. Excess Air (percent oxygen)	4.5%	2.4% to 5.8%
2. Burner Tilt (± degrees from horizontal)	0°	+18° to (-20°)
3. Fuel Air Dampers (percent open)	100%	100% to 50%
4. Auxiliary Air Dampers (percent open)	20%	0% to 40%
5. Bottom Auxiliary Damper (percent open)	50%	0% to 100%
6. Overfire Air Dampers (percent open)	0%	0% to 100%
7. Overfire Air Tilt (± degrees from horizontal)	Not Applicable	+30° to (-10°)

ECONOMIC AND ENGINEERING ANALYSIS
OF
ARCH-FIRED FURNACES

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ABSTRACT

Foster Wheeler Energy Corporation has performed an evaluation of the potential for utilizing arch firing as a means of obtaining low NO_x emissions. Arch firing is one of the original methods used for burning pulverized coal.

As reported in the 1980 Joint Symposium, arch firing is an inherently low-NO_x combustion process, with emissions of 200 to 350 ppm (at 3 percent O₂) measured from units of 80, 125 and 265 MW. This study evaluated the engineering feasibility of arch firing as a NO_x control approach for new boilers by developing preliminary designs for both natural circulation (sub-critical) and once-through (supercritical) 500 MW units for bituminous coals. Capital costs were estimated and compared to those conventional units capable of similar NO_x emissions. The results indicated that for the design assumptions of this study, capital costs for modern arch-fired boilers can be \$6 to \$30/kW greater than conventional units, depending on furnace width (Burner Zone Liberation Rate) and NO_x emissions. Accordingly, unless design improvements are identified that reduce furnace width, arch firing for the purpose of NO_x control alone may not be cost-competitive with alternative combustion controls.

Down-firing is one of the earliest methods of burning pulverized coal. In the early concepts all of the combustion air entered the furnace along with the coal in the vertical direction. Eventually, the combustion method evolved into the arch-fired system where the coal and a portion of the combustion air is injected from the arch with the remaining air entering the

furnace along the vertical wall beneath the arch. This results in a long, J-shaped flame which is inherently staged and, therefore, produces low levels of NO_x.

The majority of arch-fired steam generators are used to fire difficult to burn fuels such as anthracite and coke. However, there are twelve units in the Wisconsin Electric Power Co. system (WEPCo) which fire bituminous coal. Since these units were all built prior to 1960 and are significantly lower in NO_x emissions than other units, the Electric Power Research Institute (EPRI) contracted with Foster Wheeler Energy Corp. (FWEC) to evaluate the emissions performance of these units, perform an engineering evaluation of the design, and prepare cost estimates for new 500 MW units designed to achieve minimum NO_x. Emissions data from the WEPCo units was taken by KVB, Inc., under a separate EPRI contract. This paper summarizes the evaluation and presents the NO_x predictions and cost estimates.

EXISTING UNIT DATA EVALUATION

A key element in low NO_x boiler design is the Burner Zone Liberation Rate. This is a function of boiler heat input and heat transfer surface in the burner zone. Its influence is on flame temperature and, therefore, thermal NO_x generation. A boiler designed for a given capacity will have lower thermal NO_x generation when the burner zone surface is increased. Consequently, the effect of Burner Zone Liberation Rate (BZLR) on the WEPCo units was evaluated first.

Fig. 1 compares the elevation and plan views of the three unit sizes within the WEPCo system. The 80 MW Port Washington units (2-5) have open furnaces; Oak Creek 1-4 (125 MW) have three water-cooled division walls beneath the arch in addition to three steam cooled walls in main furnace zone. It was expected that the division walls would have some effect on NO_x.

The WEPCo arch-fired boilers are the only ones in operation which are one-wall fired (i.e., use a single arch); all others are opposed-fired. Consequently, it was necessary to develop a definition for burner zone surface which is relevant to single arch units.

Fig. 2 shows the two definitions considered:

- A₁ is the total area of the heat transfer surface between the arch and the hopper knuckle and twice the plan area. Thus:

$$A_1 = 2 (D \times W + W \times H + H \times D + nd \times H)$$

where

- D = furnace depth under arch
- W = furnace width
- H = height along arch wall from arch to hopper knuckle
- d = division wall depth (under arch)
- n = Number of division walls

- A_2 considers only heat transfer surface beneath the arch

$$A_2 = 2 [(n + 1) d \times H + d \times W + W \times H]$$

In each case the flame is enclosed in a region bounded by either tube wall or an imaginary planar surface through which radiation passes toward an actual surface. Thus, the respective BZLR's would be defined as:

$$(BZLR)_1 = Q/A_1$$

$$(BZLR)_2 = Q/A_2$$

and $(BZLR)_2$ will always be greater than $(BZLR)_1$. Q is net heat input to the burner zone.

A_2 has been considered because of the shape of the down-fired flame and the large distance between the flame axis and the rear wall. These would indicate that a large portion of the sidewall surface and the plan areas beneath the convection pass are of small effect in reducing flame temperature. However, the validity of this choice must be demonstrated by data evaluation.

When developing a NO_x vs. BZLR curve the proper conditions are:

- NO_x emission at full load
- Corresponding BZLR
- All boilers in the data set to be of similar design
- All boilers' firing systems to be of similar design
- For an accurate determination a large number of BZLR's should be used.

Clearly, the Port Washington and Oak Creek 1-4 units meet the criteria of design compatibility, whereas Oak Creek 5 and 6 belong to a separate data set. Consequently, only two data points are, in fact, available for the former group while one is available for the latter. This is a direct result of the geometric and hardware identity between the units within each group.

Boiler heat input (obtained from operating data, subsequently discussed) and NO_x emissions are required. The following table summarizes the relevant data all normalized to common conditions for the respective groups (NO_x evaluation is discussed in the following section):

Boiler Group	Port Washington	Oak Creek 1-4	Oak Creek 5&6
NO_x ppm @ 3% O_2	350	300	200
Normalized Load (MW)	85	125	275
Q/A_1 (10^3 Btu/hr ft ²)	175	117	147
Q/A_2 (10^3 Btu/hr ft ²)	320	185	268

The NO_x data is plotted against both Q/A_1 and Q/A_2 in Fig. 3. It is immediately apparent that Oak Creek 5 and 6 have significantly lower NO_x emissions than do the other two groups. Furthermore, regardless of the definition of BZS (A_1 or A_2), the Q/BZS value for Oak Creek 5 and 6 is approximately midway

between those of the other two groups. From the operating and design information available, the only reasonable explanation for this behavior is that the combustion system differences are responsible.

Since there are no other NO_x vs. unit parameter design curves available (the last WEPCo-type of arch-fired unit was built more than ten years prior to the existence of NO_x limits), it is not clear from the above data which BZS definition is more representative of the phenomena. A comparison has, therefore, been made between the data in Fig. 3 and the NO_x vs. Q/BZS relationships developed for Foster Wheeler wall-fired units of both pre-NSPS and NSPS design. This is shown in Fig. 4. It can be seen that the data represented by Q/A_1 has a much steeper slope (by a factor of 2.3) over that of the Q/A_2 set.¹

The NO_x vs. Q/BZS relationship is an indication only of the variation of thermal NO_x with heat transfer surface area. Thus, a rapid increase in NO_x with Q/BZS is indicative of a relatively high initial flame temperature. Comparing the low NO_x curve to the uncontrolled NO_x curves in the range of $Q/\text{BZS} = 150,000 \text{ btu/hr-ft}^2$ shows that the Q/A_1 slope is significantly greater than the slope of the controlled NO_x curves for wall-fired units. It has been Foster Wheeler's experience that such a situation can exist only if a very high turbulence pre-mix combustion system is used. This is demonstrably not the case with the arch-fired units under study.

Consequently, the relationship between NO_x and Burner Zone Liberation Rate believed to be most representative of arch-fired units is that of Q/A_2 .

BURNER ZONE SURFACE: OPPOSED ARCHES

Large units would only be designed with two opposed arches. This configuration is preferable and has been used by Foster Wheeler for many years for units designed to burn low volatile fuels (coke, anthracite). Steam generator sizes have ranged from 40 MW to 500 MW.

The Burner Zone Surface used for such units is the A_1 area defined in the previous section. To determine whether this should be retained in the design study of large bituminous coal-fired units a comparison of surfaces A_1 and A_2 for opposed-fired units was made. Fig. 5 defines the dimensions and geometries. The resultant areas are:

$$\begin{aligned} A_1 &= 23,391 \text{ ft}^2 \\ A_2 &= 23,487 \text{ ft}^2 \end{aligned}$$

500 MW UNIT DESIGN

The method used to evaluate the cost-effectiveness of arch-firing was based upon utilizing design and performance information from a typical 500 MW opposed fired unit as a basis for comparison. A unit which was designed to fire sub-bituminous coal as the primary fuel with bituminous as an alternate was chosen. The performance specifications were used as the basis for designing a 500 MW arch-fired unit. Since arch firing requires a wider, and

therefore more costly boiler, the initial emphasis was placed on minimizing unit size.

The criteria chosen were based on those in use at WEPCo so that a minimum of projections were necessary. Since the primary purpose of the investigation was the design of a low NO_x arch-fired boiler, a key design parameter was the Burner Zone Liberation Rate. The value chosen for the base design was that of Q/A_2 for Oak Creek 5/6. Secondly, to obtain a rough estimate of cost sensitivity, an alternate unit was designed with a value of BZLR based on Q/A_1 for Oak Creek 5/6. Thus, the alternate unit is a physically much larger boiler, for the same 500 MW capacity. Fig. 6 compares the physical relationships between the wall-fired unit and the two arch-fired designs, all being natural circulation boilers. Also, for comparative purposes, a once-through unit the same size as the base arch design was evaluated.

In order to facilitate the design effort the same boiler auxiliaries were used for all units (pulverizers, air heaters, fans, etc.). These had already been chosen for the wall-fired unit. The economizer exit flue gas temperature was maintained constant for all units. Therefore, as the lower furnace's heat transfer surface increases, resulting in lower furnace exit gas temperature (FEGT), the total convection pass surface required must increase. This is so since steam flow and temperature requirements are held constant, requiring no change in heat pick-up for the different unit designs. The only means of maintaining steam temperature in the reduced heat head environment is with more convection surface.

The predicted effect on NO_x emissions is summarized in Fig. 7 where WEPCo data is used as the basis for the new unit projections. Note that most field data taken at WEPCo was at high excess air so that, for meaningful comparisons to be made, all data was normalized to 6% O_2 . The Oak Creek 5/6 data was then projected to 4% O_2 based on the NO_x vs. O_2 characteristics of Oak Creek 5/6.

It can be seen that $0.2 \text{ lb } \text{NO}_x / 10^6 \text{ Btu}$ is attainable with the base arch-fired design and 0.15 is approachable with the alternate. These projections are based on WEPCo NO_x data and furnace design parameters. A reasonable expectation is that lower NO_x levels should be attainable with more modern combustion equipment optimized for low NO_x .

COST CONSIDERATIONS

The three arch-fired configurations, base and alternate natural circulation and a once-through unit, were cost-estimated on a delivered and erected basis. In each case the boiler manufacturer's scope was the same. There is, therefore, a direct cost comparison between the base wall-fired unit and the various arch designs.

The cost comparisons are summarized in the following table:

	<u>Price Comparison and Summary</u>			
	BASE UNIT WALL-FIRED	BASE ARCH	ALT.-ARCH.	OTU
Materials & Fabrication	\$42.845 x 10 ⁶	\$44.066 x 10 ⁶	\$52.653 x 10 ⁶	\$46.725 x 10 ⁶
Erection	14.385	16.250	19.650	16.646
Total	57.230	60.316	72.303	63.372
% Change	0	5.4	26.3	10.7

All prices referenced to October 1980

SUMMARY AND CONCLUSIONS

The NO_x and cost evaluations indicate that NO_x levels in the 0.2-0.3 lb/10⁶ Btu range are feasible with lower levels possible. It had already been known that arch-firing is more costly than horizontal firing, which is the reason that the former is mainly used for low volatile, difficult to burn fuels. Since NO_x levels below 0.3 are obtainable with new wall-fired units, arch firing would not be cost competitive, when using WEPCo design parameters, unless:

- furnace width can be reduced
- the conservative lower furnace design and lower FEGT permits greater fuel flexibility
- SO₂ capture is greater than that obtainable with horizontal firing.

There are no technical or engineering obstacles with extrapolating the arch-fired design, for either subcritical or supercritical pressures, up to 1230 MW.

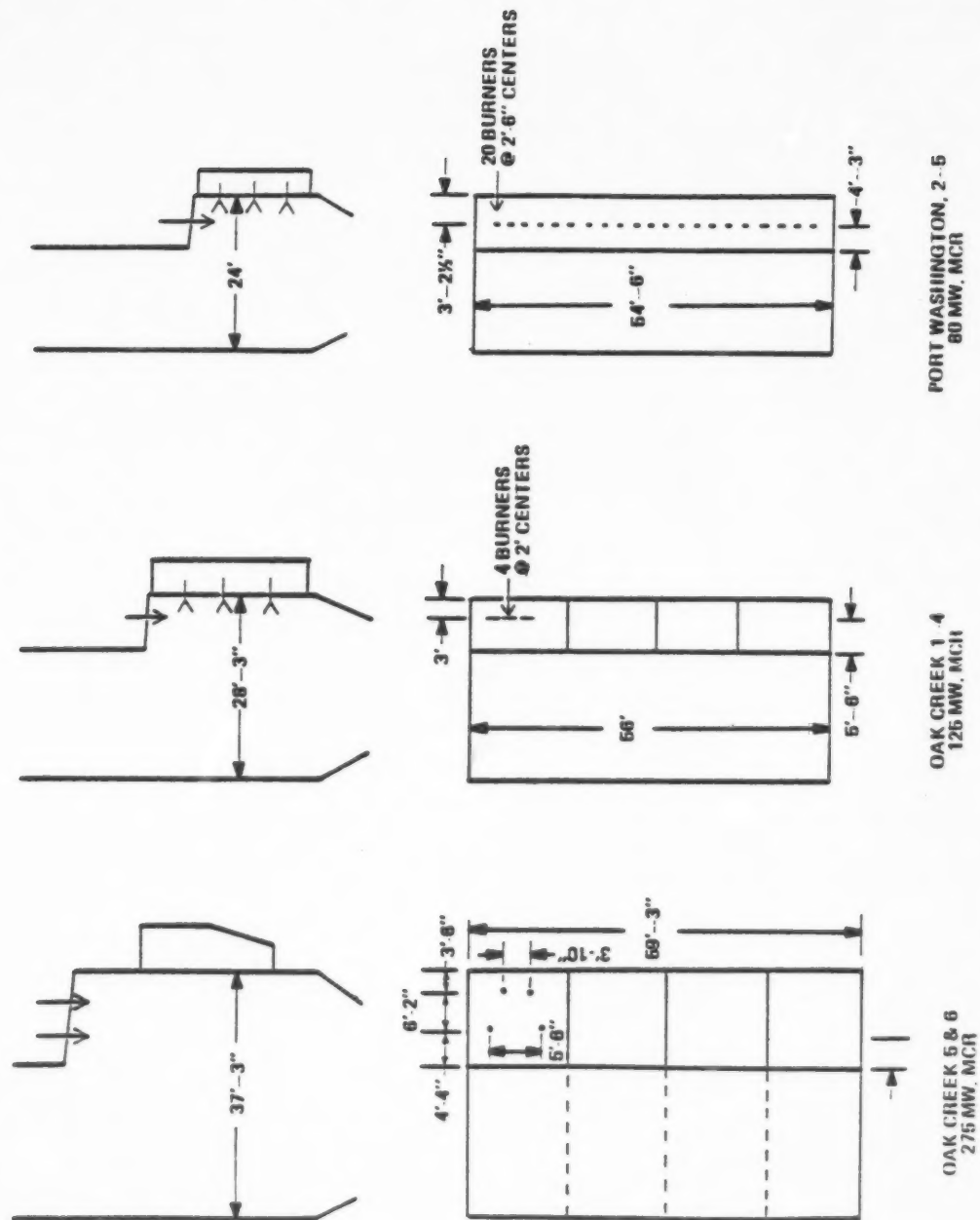
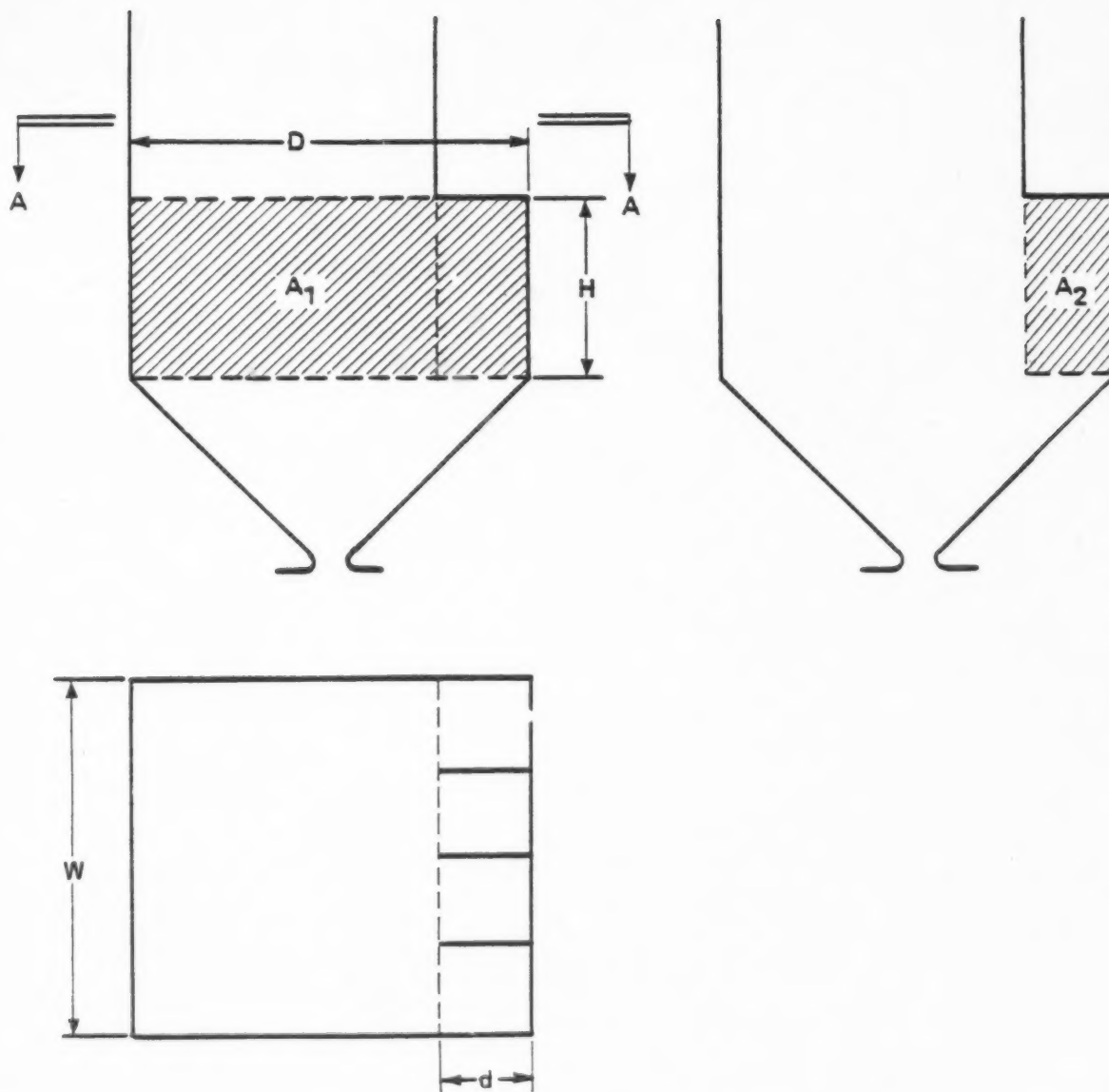


FIGURE 1. GEOMETRICAL COMPARISON OF ARCH-FIRED UNITS



SECTION AA

FIGURE 2. DEFINITION OF TWO BZS ARRANGEMENTS

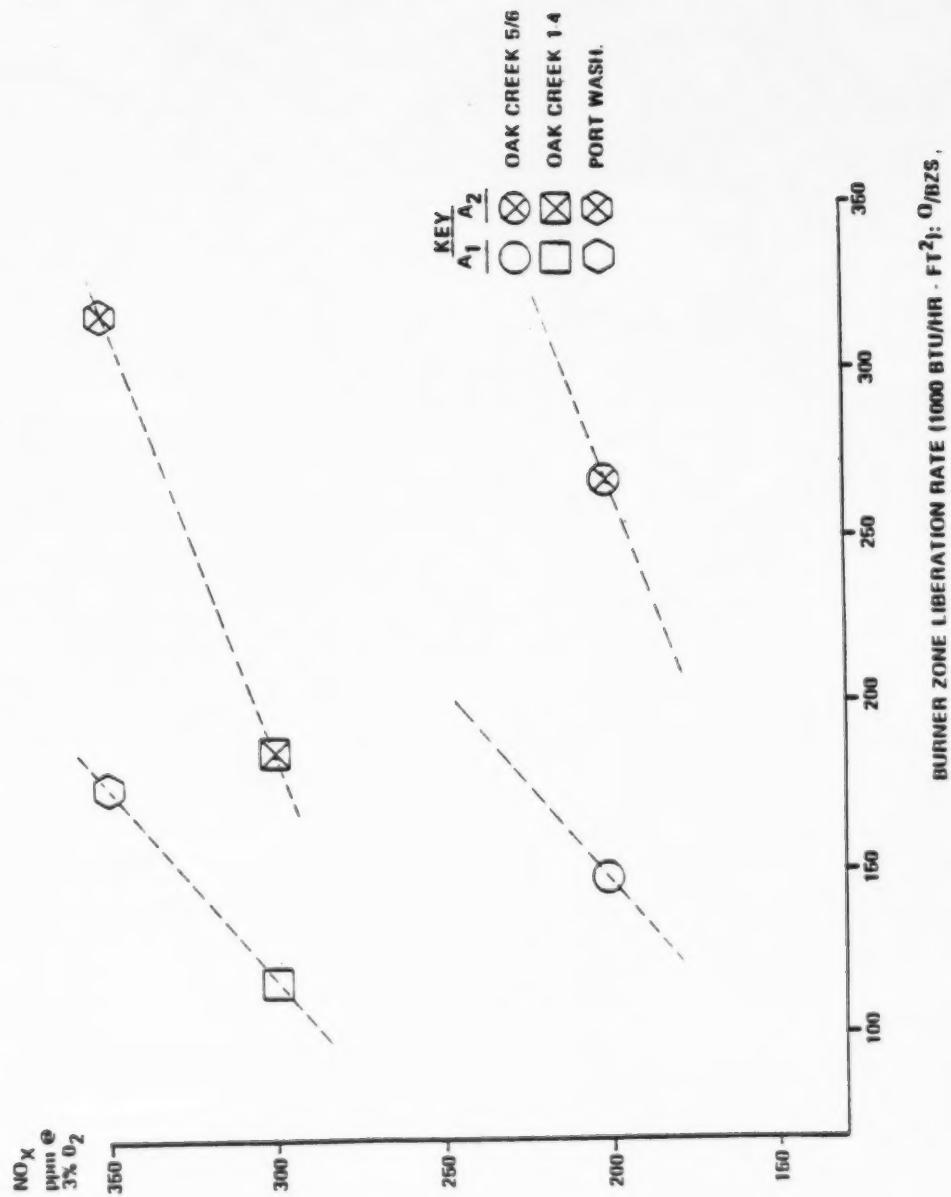


FIGURE 3. BURNER ZONE SURFACE COMPARISON

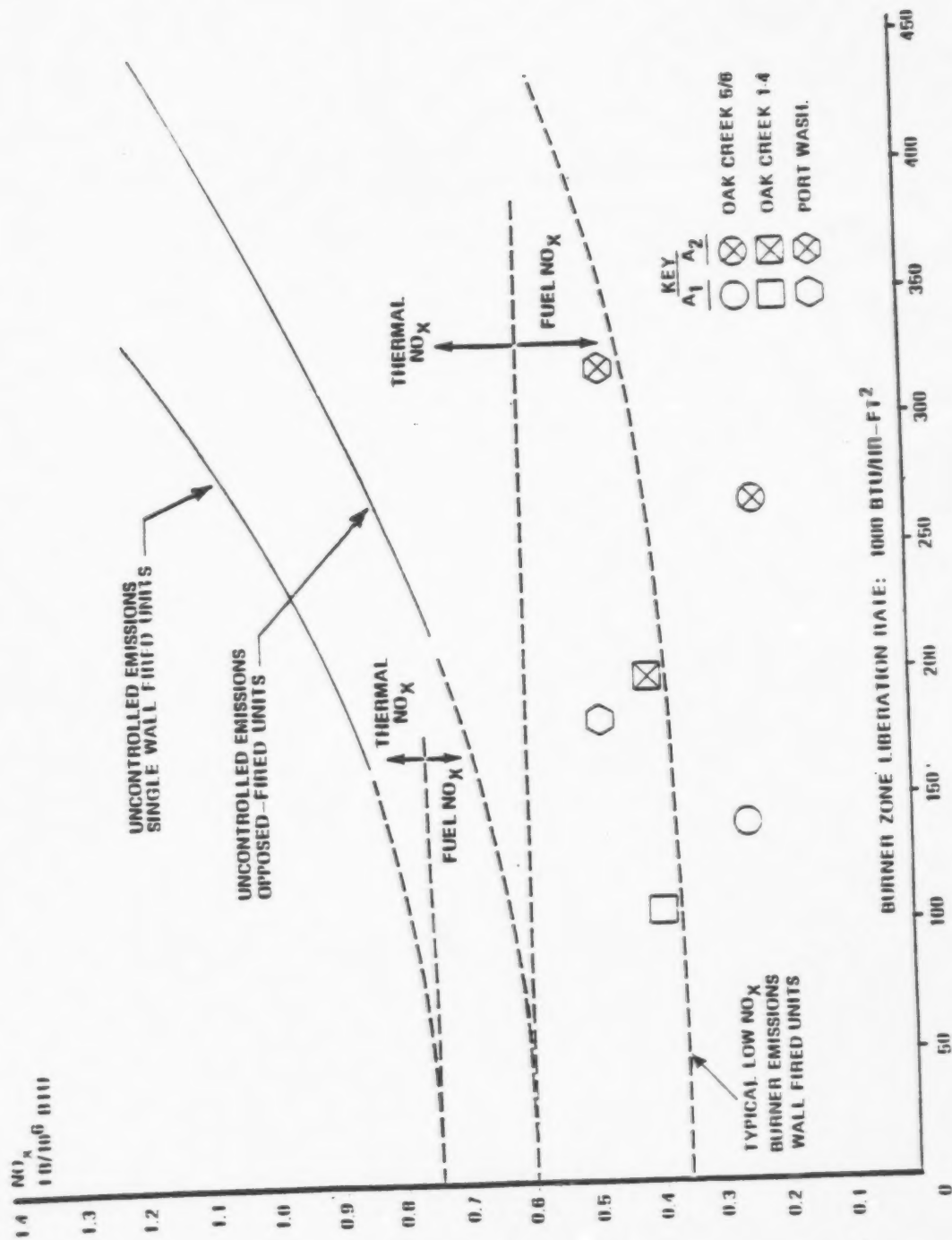
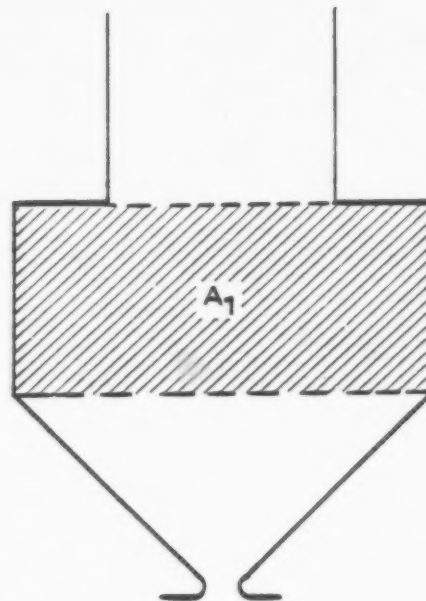


FIGURE 4. NO_x VS Q/BZS

AREA A_1
 $A=23,391 \text{ ft}^2$



AREA A_2
 $A=23,487 \text{ ft}^2$

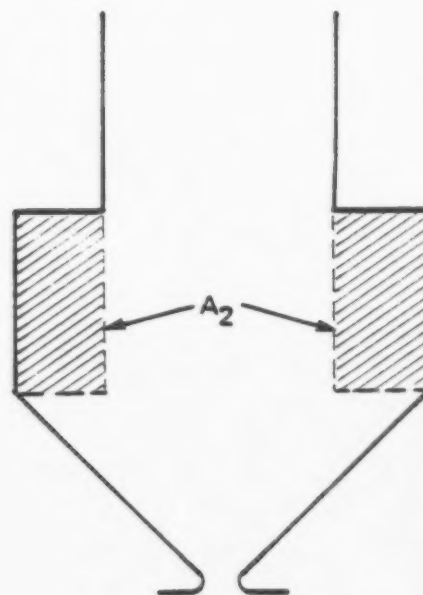


FIGURE 5. OPPOSED-FIRED UNIT: BZS COMPARISON

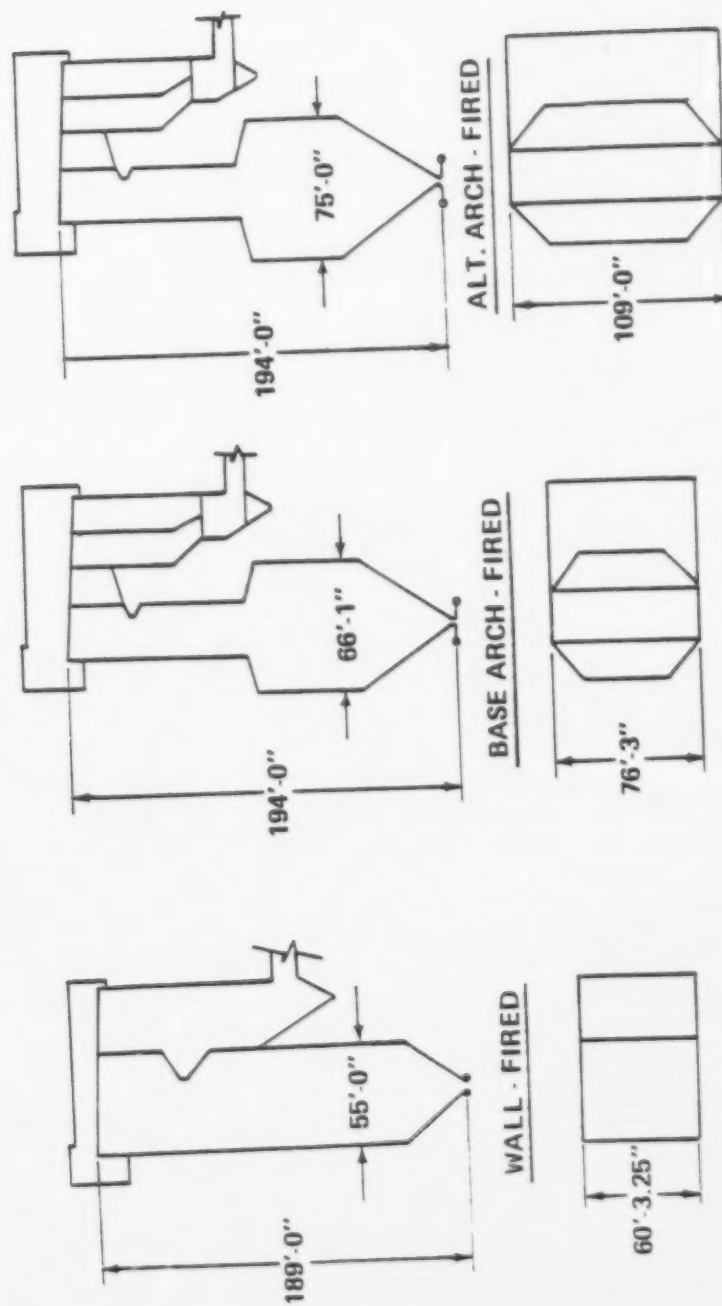


FIGURE 6. NATURAL CIRCULATION UNITS - OVERALL SIZE COMPARISON

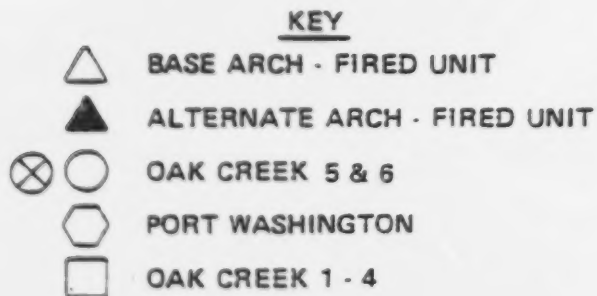
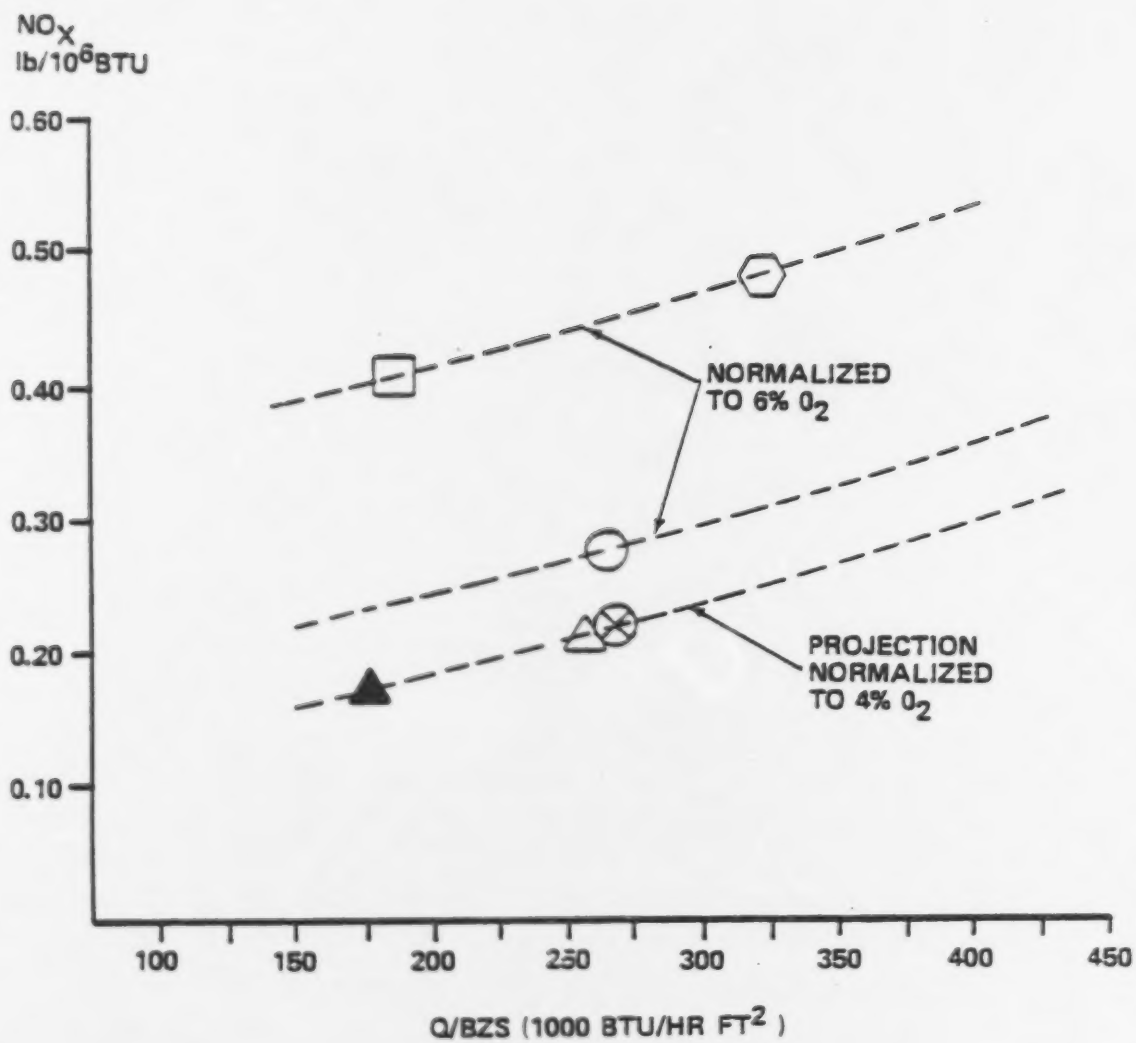


FIGURE 7. NO_x PROJECTIONS FOR ALTERNATE 500 MW DESIGNS

STATUS OF JAPANESE TECHNICAL DEVELOPMENT
FOR
COAL COMBUSTION NO_x CONTROL

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ABSTRACT

The Electric Power Development Co., Ltd. reviewed NO_x combustion control R&D for coal-fired power plants at two previous NO_x Symposia. This third presentation mainly describes the first year operational results of the Matsushima Thermal Power Station (500 MW x 2 units) which was designed based on the results of our R&D program. The paper also concerns the NO_x control design of the Takehara Thermal Power Station, unit No. 3 (700 MW) which is currently under construction and scheduled to start operation in March 1983. The infurnace DeNO_x process that is being developed by the Japanese boiler manufacturers as a new low-NO_x combustion technology is also briefly discussed.

INTRODUCTION

The Japanese Government ambient NO_x standards were revised to a NO_x level from 0.04 to 0.06 ppm in July, 1979. This applies to every area in Japan. The NO_x emission standard when employing coal as fuel is 400 ppm by the National Law. For newly installed coal-fired power plants, the final pollution control agreement is arranged between a local government and the power company in order to obtain citizen's consensus considering Japanese situations. The pollution control agreement includes NO_x, SO_x, dust, etc. More strict requirements for NO_x are imposed as compared with the National Law. Emission values in the pollution control agreement are based on the consensus through discussions considering whether population is dense or sparse near the power station, what level is allowed for other industry groups and capabilities of NO_x removal technology. Recently, the allowable emission values have become more strict with advancement of technology.

Power plants are forced to rely upon coal imported from overseas since an increase of production of domestic coal is not expected. Coal inflammability, slagging, fouling and N content vary in accordance with coal mining districts, so that various coal property considerations must be taken in to account when designing boilers. For that reason, the EPDC has conducted combustion tests using test furnaces, especially to establish NO_x reduction technology for coals anticipated for use. This work is done jointly with the boiler manufacturers and seeks to develop guidelines to operate commercial furnaces. In this respect, an important point to be noted is the correlation between the test and commercial furnaces. The correlation between results from the test furnace and those from the commercial furnace has been confirmed.

Note that evaluating NO_x reduction does not mean that operability, boiler efficiency (unburned carbon content), slagging and fouling characteristics are not considered. On the contrary, NO_x reduction must be evaluated with those conditions completely satisfied.

This paper will describe operating results of boilers at the Matsushima Thermal Power Station, mainly focusing NO_x control, and will review design specifications of Takehara boiler No. 3 now under construction and will provide a brief evaluation of the in-furnace DeNO_x process.

DESIGN OF BOILER AT MATSUSHIMA THERMAL POWER STATION

BOILER SPECIFICATIONS

The EPDC Matsushima Thermal Power Station boilers (units No. 1 and No., 500 MW each, 1000 MW in total) are super critical-pressure, large-capacity, exclusively coal-fired boilers and are adaptable to a variety of coals with different properties (because of main use of imported coals). This plant is fully automated and of the latest design. In addition, it has the following features stressing economy, reliability, safety and pollution control in the basic planning and design of the plant:

- (1) Use of the super critical-pressure once through boiler (indoor type)
- (2) Use of the low NO_x pulverized-coal burner (SGR burner)
- (3) Use of the moving vane variable axial type forced and induced draft fans (FDF/IDF)
- (4) Use of the cold primary air system in combination with a pressure mill and a trisector air preheater (AH)
- (5) Use of full automation

Major items on design of boilers are shown in Table 1, and types and properties of as-planned fuels are shown in Table 2.

The boiler plant specifications are shown in Table 3, and the side view of the boiler is shown in Figure 1.

DESIGN PHILOSOPHY OF LOW- NO_x SGR BURNER

The NO_x generation and suppression mechanisms were theoretically and experimentally studied for the coal-fired low- NO_x burner. Combustion tests with overseas coal having a high nitrogen content were mainly conducted at the manufacturer's test furnace to develop low- NO_x SGR burners and ultimately enable their application to the Matsushima Thermal Power Station.

The SGR burner is capable of reducing NO_x , while maintaining satisfactory combustion, based on the following three effects:

- (1) Tangential (corner) firing
- (2) Overfire air (OFA)
- (3) Separate gas recirculation (SGR)

The shield effects of inert gas (SGR) and self recirculation gas (in-furnace combustion gas self supplied to burner jets) control combustion air flow rate to a minimum as necessary to minimize NO_x emission. Stable combustion is kept by satisfactory firing, and sufficient air is supplied to a combustion-complete zone (having low flame temperature and a low NO_x emission level) to sufficiently mix fuel with air at the mid-section of the furnace to produce satisfactorily even combustion. Moreover, the burner is expected to suppress generation of unburnt carbon with a long spiral combustion track. Figure 2 shows the schematic diagram of the pulverized-coal SGR burner at the Matsushima Thermal Power Station. Figure 3 shows the gas mixing system diagram. Part of the combustion gas is supplied from the outlet of the hot side ESP. It is divided into SGR and GM after passing through the separate gas recirculation mixing fan (SGRF). SGR is jetted from SGR nozzles provided at the top and bottom of the coal burner without being mixed with the secondary air for combustion. Meanwhile, GM is mixed with the secondary air through the gas mixer provided in the secondary air duct and jetted from secondary air nozzles in the wind box. Distribution of SGR and GM is performed by the distribution damper.

South Africa coal having a comparatively high nitrogen content and a high NO_x emission level was also tested in addition to as-planned coals shown below. The burner was designed based on the following target NO_x values.

Target NO_x emission level (design)	
Coal	Target (ppm $\text{O}_2 = 6\%$)
Chinese	280 ppm and below
Australia	280 ppm and below
South Africa	290 ppm and below
Domestic	280 ppm and below

OPERATION RESULTS OF MATSUSHIMA THERMAL POWER STATION

This section discusses operational results of the Matsushima Thermal Power Station. As shown in Table 4, the station has extremely high availability. The property of coal used up to now is shown in Table 5. Coal properties concerned with combustion are as follows:

Fuel ratio: 1.13 to 2.17 (Fuel Ratio = Fixed Carbon/ Volatile)

N content: 0.9 to 1.8

STATIC CHARACTERISTICS OF BOILER

This boiler is designed for Chinese Daido coal as a main fuel that is 1) as high as 2.0 in fuel ratio, 2) comparatively low in flammability and 3) comparatively high in slagging characteristic (ashes are softened at about 1200°C).

When Daido coal was combusted, the results showed that static characteristics such as steam temperature, pressure, gas temperature, air and a gas draft in each section were almost the same as target values. Satisfactory results that exceeded target values were also obtained for boiler efficiency.

Figure 4 shows the target values and measured values of steam/boiler feed water temperatures in the main steam system. Temperature in the main steam system is kept at the rated value over a load range from 100% to 30%, and temperature in each section is almost the same as the target value.

Figure 5 shows reheat steam temperature, and the satisfactory temperature characteristics obtained over a wide load range from 100% to 30% as planned. At that time, steam temperature control running conditions such as the excess air ratio, gas recirculation flow rate, a burner tilt angle were also almost the same as the target values.

As shown in Figure 6, boiler efficiency exceeded the target value under each load. This is because low flue gas temperature was obtained.

Air and gas draft losses are lower than the target values. The FDF and IDF were marginally run and plant power consumption was reduced.

Concerning static characteristic variations of the boiler operated with 16 types of coal up to September, 1982 since test run started, deposition of slag on the furnace is extremely low with every type of coal, and blowing slag on the furnace and deposits on the superheater and the reheater is as infrequent as once a day. In contrast, a considerably outstanding difference is noted in steam temperature characteristic. Namely, there is a tendency that absorption of heat into the furnace increases for highly combustible coals with a low fuel ratio (like Plateau, Korowio, King and Orchat Valley, U.S.A. and domestic Ikeshima). Furthermore, reheat steam temperature is difficult to rise and recirculation gas flow rate increases as shown in Figure 7. This occurs because such types of coal have good inflammability and have heat release profiles approaching that of heavy oil.

OUTLINE OF LOW-NO_x SGR BURNER PERFORMANCE

The coal-fired low-NO_x SGR burner has been developed through theoretical analysis of pulverized coal combustion and tests using the combustion furnace at Mitsubishi Heavy Industry. As shown in Figure 2, it has a feature that recirculation gas nozzles (SGR) are inserted between coal air nozzles and auxiliary air nozzles.

This SGR burner was introduced into Matsushima boilers No. 1 and No. 2 to suppress to a minimum NO_x in imported coal like South Africa coal which contains comparatively high nitrogen and produces high NO_x emission. As a result, it was confirmed that NO_x and Ignition Loss (IGL) were suppressed as planned and that poorly combustible coal like Witbank coal, South Africa was stably combusted under partial load running by applying the SGR.

NO_x and unburned carbon content in all types of coal completely satisfy target values.

NO_x is effectively reduced, irrespective of types of coal, by the use of overfire air. Meanwhile, effectiveness of NO_x reduction was noted in Witbank coal, Elmero coal and Daido coal (having high fuel ratio) using the SGR.

Though some differences were found depending upon types of coal, NO_x was almost constant over the load range from 100% to 50%, and an increase of NO_x was not found under partial load as seen in conventional boilers. That is because reheat steam temperature is controlled by the recirculation gas, thereby avoiding increase of the excess air ratio under partial load.

Concerning combustion under boiler loads as low as 50% or less, gas temperature in the furnace lowered and radiation lessened, so that a tendency for the firing point to become more distant from the burner port than under high load was found in some poorly combustible coal. Reduced flame scanner signal strength was also observed. Even in that case, fire balls were stably formed and in-furnace draft variations were low. If SGR flow rate is increased in such a case, the firing point comes close to the burner port and flame scanner output becomes stable. The SGR thus contributes to firing conditions under partial load.

NO_x EMISSION CHARACTERISTIC

Combustion with overfire air (OFA) at constant SGR flow rate results in NO_x reduction lower than the value targeted. However, the operation range is restricted at some NO_x level by an increase of the unburned carbon (IGL) and static characteristics. As shown in Table 6, both NO_x value and IGL (%) are lower than target values.

EFFECTS OF NO_x REDUCTION WITH VARIED CONDITIONS

(a) O₂ at economizer outlet vs NO_x

As shown in Figure 8, NO_x increases linearly with an increase of $\text{O}_2\%$ in each type of coal. [letters T, A, P, Y and E denote five test coals. Refer to Table 2 for partial coal identification].

(b) OFA ratio vs NO_x

As shown in Figure 9, NO_x varies almost linearly up to an OFA ratio of 25% in each type of coal but effectiveness of NO_x reduction slows down at 25% or more.

The NO_x reduction with OFA is greatest for South Africa (Witbank) coal having a high N content and a high fuel ratio.

(c) SGR flow ratio vs NO_x

Effectiveness of NO_x reduction by the SGR flow ratio is low as shown in Figure 10, but is effective for South Africa (Witbank) coal having a high fuel ratio.

The SGR is greatly effective under partial load (250 MW).

(d) Burner Tilt vs NO_x

As shown in Figure 11, there is a tendency that the NO_x emission level increases with a rise of burner tilt angle in each coal. Especially, it increases greatly at 10° or higher.

(e) Burner Stage vs NO_x

As shown in Figure 12, NO_x is effectively reduced by shutting off the top burners. It is supposed that this simulates OFA effects owing to mill purge air and air leaked from dampers.

(f) Differential pressure in wind box vs NO_x

There is a tendency that NO_x rises when differential pressure increases, and the flame ignition point becomes more distant from the burner nozzle.

As shown in Figure 13, 110 mmAq is optimum at 500 MW; 70 mmAq is optimum at 250 MW from combustion point of view.

(g) Secondary air damper opening for fuel vs NO_x

There is a tendency that when the secondary air damper is opened, NO_x lowers. Furnace heat load in the combustion zone is high, especially at 250 MW, and furnace metal temperature rises locally.

As shown in Figure 14, an opening of 2.5/5 is optimum at 500 MW; 1.5/5 at 250 MW is optimum from combustion point of view.

(h) Load vs NO_x

There is a tendency that NO_x decreases slightly under partial load as shown in Figure 15, but it increases in comparison to its minimum values.

(i) GR vs NO_x and Air/Coal (A/C) vs NO_x

Effects on NO_x reduction by GR and A/C are not almost noted in each type of coal

NO_x EMISSION VARIATION

NO_x emission level is almost constant when operating conditions are stable. Figure 16 shows NO_x emission variation when load changes.

When mill starts or stops, NO_x level varied. This is a temporary phenomenon. Generally speaking, we believe that stable NO_x emission level can be achieved during normal boiler operation.

CARBON LOSS (IGL) CHARACTERISTIC

The IGL is mostly a function of the fuel ratio, ash content, the pulverized-coal grain size, OFA ratio, SGR ratio and total GR ratio, and has the following relationship:

High-fuel-ratio, low-ash-content coal > high-fuel-ratio, high-ash-content coal > low-fuel-ratio coal

Combustion test results using six types of coal show the following order:

Witbank coal > Daido coal > Elmero coal > Mirror blend coal > Ikeshima coal > Plateau coal

The relationship of IGL to various parameters is shown in Figures 17 through 20 and summarized as follows:

o Relationship between Pulverized-Coal Grain Size and IGL

The IGL increases in proportion to the pulverized-coal grain size as shown in Figure 17, and the most extreme case is South Africa (Witbank) coal.

o Relationship between OFA Ratio and IGL

As shown in Figure 18, IGL increases in proportion to the OFA ratio, and the most extreme case is Chinese (Daido) coal.

o Relationship between Total GR Ratio and IGL

As shown in Figures 19 and 20, IGL increases in proportion to the total GR ratio, and the most extreme case is Chinese coal.

COMBUSTION CHARACTERISTICS OF OVERSEAS COAL INFLAMMABILITY (TEST RESULTS)

Generally, coal flammability depends upon the ratio of volatile matter, fixed carbon, fuel ratio, carbon/hydrogen, calorific value, ash content and moisture content.

The relative ignition point distance under partial load for every type of coal is shown below.

	Witbank	Daido	Elmero	Plateau
Relative burner port-to-ignition point distance (OFA: 20%, SGR: min)	3	1	0.8	0.2

As a result, Plateau coal, Ikeshima coal, Mirror blend coal, Elmero coal, Daido coal, Reatsproot coal and Witbank coal are listed in this order of inflammability. When deciding inflammability of coal, it must be done in comparison to the flammability index of design coal or in accordance with the shape and size and the combustion system of the boiler.

o Slagging and Fouling Characteristics

Generally, items that govern the slagging and fouling characteristics of coal are ash content, calorific value, ash melting temperature, ash fluidity temperature-ash softening temperature, the base/acid ratio, the $\text{Fe}_2\text{O}_3/\text{CaO}$ ratio and Na_2O in ashes.

Concerning fouling, Economizer outlet gas temperature variation is 3 or 4°C (7°C maximum in Reatsproot coal) before and after the soot blower at the rear duct is operated once a day. An Economizer outlet gas temperature value is stable between 340°C and 350°C.

No trouble due to slagging and fouling has ever occurred in any coal used. However, furnace metal temperature changes abruptly because of deposition and detachment of furnace slag. This phenomenon depends upon types of coal and blended coal fired.

Furnace wall tube metal temperature and slagging behaviors for every type of coal are shown in Table 7.

COAL QUALITY EVALUATION/DISCRIMINATION (SCREENING) METHOD

Results obtained by combusting various overseas coals in boilers No. 1 and No. 2 (designed for Daido coal) show that it will be important to use an experimental formula for coal quality evaluation and screening in order to maintain future reliable operation. This paragraph describes the method. Liquid fuel or gaseous fuel is constant in composition and property. Otherwise, it is moderated until its components/property are constant and then shipped to the user, while coal mined in the production district is shipped and used directly. Furthermore, even coal in the same production district varies in property with different mining

timings and mining locations. The relationship between the acceptance date and industrial analysis values of Daido coal is shown below as an example.

Industrial Analysis Value Date	Calorific Power (kcal/kg)	Proper Water Content (%)	Fixed Car- bon (%)	Volatile Content (%)	Ash Con- tent (%)	N Con- tent (%)
As-specified coal	7,100	2.8	58.8	28.5	9.9	0.80
August, 1980	6,940	3.9	57.6	25.8	12.7	0.84
November, 1980	7,210	3.3	60.4	27.8	8.5	0.78
October, 1980	6,670	3.4	56.9	25.5	14.2	0.78
October, 1980	6,220	3.2	61.7	26.5	8.6	0.79

As seen in the example of Daido coal, even coal of the same type in the same production district is highly variable in composition.

o Inflammability Discrimination Method

Generally, discrimination of inflammability based on analysis values of coal is as follows:

- (1) Coal having high calorific value is superior in inflammability.
- (2) Coal having a high volatile matter is superior in inflammability.
- (3) Coal having a high ash content is inferior in inflammability.
- (4) Coal having a high fuel ratio, i.e., fixed carbon/volatile content, is inferior in inflammability.
- (5) Coal showing a high carbon/hydrogen ratio is inferior in inflammability.

Where combusting conditions (Moisture, air/coal, pulverized coal grain size) are constant for every type of coal and combustion velocity (due to ash content) is corrected based on Matsushima design coal, inflammability is represented as a flammability index (FI) and an index by expressions (1) and (1)' below.

$$FI = \frac{Hh}{FR} (115 - A) \frac{1}{105} \cdot \frac{1}{3500} \quad \dots (1)$$

$$\text{Flammability index} = \frac{Hh}{FR} (115 - A) \frac{1}{105} \quad \dots (1)'$$

where

Hh: higher calorific value of dry base (kcal/kg)

FR: fuel ratio

A : ash (%)

This permits decision of coal for an acceptable quality level (AQL) of flammability in comparison with design coal.

o NO_x Emission Discrimination Method

Coal having high N content and a high fuel ratio shows high NO_x emission.

This relationship is represented by expression (2) below.

$$NO_x \text{ concentration (ppm)} = \frac{10}{0.1} (N - N_0) - \frac{5 \text{ or } 8}{0.1} (FR_0 - FR) + NO_{x0} \quad \dots (2)$$

where

N : N content in coal (%)

N_0 : N content in standard coal (%)

FR: fuel ratio

FR_0 : fuel ratio (standard coal)

NO_x : NO_x value of standard coal

10/0.1: NO_x rises 10 ppm/N content of 0.1%

-5 or 6/0.1: suppression value of NO_x conversion ratio

in accordance with a volatile content, 5/0.1 is applied to coal having a fuel ratio of 1.6 or more, 8/0.1 is applied to coal having a fuel ratio of less than 1.6

For example, if Daido coal (Matsushima design coal) is used for standard coal, NO_x concentration of other types of coal can be obtained through calculation based on known coal properties.

o IGL(%) Discrimination Method

Unburned carbon content decreases in inflammable coal (flammability index large), and increases in coal having a high fixed-carbon content.

Coal having a low ash content increases in IGL(%) even if an unburned carbon content is low.

IGL (%) is approximately represented based on expressions (3) and (4).

$$\text{Ig} \cdot \text{L} = K_1 \cdot \frac{\text{Fc}}{(\text{FI}) \cdot \text{A}} \quad \dots (3)$$

$$\text{Ig} \cdot \text{L} = K_2 \cdot \frac{(\text{FR})^2}{\text{A}} \quad \dots (4)$$

where

Ig·L: unburned carbon content in ashes (%)

K_1 : coefficient, 0.7

K_2 : coefficient, 10

Fc : fixed carbon (%)

FI : flammability index

FR : fuel ratio

A : ash (%)

Coefficients K_1 and K_2 are the functions of OFA ratio and pulverized coal grain size. Combustion test results in boilers No. 1 and No. 2 show that coefficients K_1 and K_2 are as shown above for an OFA ratio from 20% to 25% and with 3% to 5% remaining through 100 mesh (coal fineness). The calculated values are well matched with actual results.

CORRELATION BETWEEN TEST FURNACE AND COMMERCIAL BOILER FOR PM BURNER.

Figure 21 shows correlation curve between NO_x emission data obtained at test furnace and data from Matsushima thermal power-plant. This shows good correlation.

Another correlation curve is shown in Figure 22. This curve shows good match between NO_x emission level of test furnace and predicted NO_x emission level of Matsushima's boiler for various kinds of coal, using SGR burner. Therefore, we feel that NO_x emission level using commercial PM burner will be the same value as predicted from the test furnace. (Concept of PM burner is shown in Figure 25.) Some industrial boilers and utility boilers with PM burners will be operated in near future. It is very important for us to investigate its actual performance. EPDC is now considering application of the PM burner to future coal fired power plants.

THE DESIGN OF NO.3 EXTENTION UNIT OF TAKEHARA THERMAL POWER STATION

A coal-firing power plant, with the largest capacity in Japan, is now under construction at Takehara Thermal Power Station of EPDC. The trial operation commenced October 1982 and the commercial operation is expected to start in March, 1983. The outline of this unit is as follows.

- o Output 700 MW x 1 unit
- o Fuel Coal (imported coal)
- o Boiler Manufacturer BHK
- o SCR Manufacturer BHK
- o Type of Boiler B & W Supercritical pressure reheat type UP boiler
- o NO_x (guaranteed at boiler) 250 ppm (O₂ = 6%, N = 1.8%)
- o NO_x (target at boiler) 200 ppm (O₂ = 6%, N = 1.8%)
- o NO_x (guaranteed at stack) 60 ppm and below (O₂ = 6%, N = 1.8%)
- o Burner type PG dual burner

PG DUAL AIR REGISTER BURNER

For the purpose of lowering NO_x generation, a burner called Primary Gas Dual Air Register (P.G. Dual Air Register) was developed by Babcock-Hitachi (figure 24). This burner is characterized by boiler flue gas injection between fuel and air streams in order to lower the temperature of the burning zone around the burner. The nozzle for pulverized coal is arranged in the centre of the air register and injects pulverized coal carried with the primary air into the furnace. The pulverized coal injection nozzle is provided with two concentric cylindrical sleeves, and the inner of the cylindrical paths formed by them is called the primary gas port and the outer the secondary air port. Furthermore, the cylindrical path formed by the outer sleeve of the secondary air port and the burner throat is called the tertiary air port. The primary gas port is designed to be capable of supplying, boiler flue gas, which is called primary gas.

To the secondary and tertiary air ports, the combustion air from the windbox is supplied. For distributing the flow of air supplied among those ports, each port is equipped at its inlet with louvre dampers, which are called the secondary air register and the tertiary air register, respectively.

COMPARISON OF NO_x EMISSION BETWEEN TEST FURNACE AND FIELD DATA

Fig. 25 shows the correlation between actual field data and test furnace data with heat release rate at the burner zone v.s. NO_x level.

This relation will be confirmed when Takehara No. 3 boiler is operating. EPDC anticipates achieving the target NO_x level.

ACTUAL EXPERIENCE ON EXISTING BOILER WITH LOW NO_x BURNER (DUAL AIR REGISTER)

The NO_x lowering effect of the retorofited boiler (Takehara Thermal No. 1 Boiler) is explained as follows.

Retorofited Points:

- (1) Installment of 2 stage combustion for lowering NO_x generation.
- (2) Retrofit replacement of originally installed circular air register with dual air register as low NO_x burner.

Boiler Specification:

Type of Boiler	B & W type
Rating Output	250 MWe
Burner Type	Circular air register is retorofitted to dual air register
2 stage combustion	OFA port, one elevation, 4 rows
Burner Position	Front 4 rows, 3 elevations (12 burners) Rear 4 rows, 2 elevations (8 burners)

EFFECT OF NO_x REDUCTION BY TWO-STAGE COMBUSTION (AT TURBINE RATING)

Figure 26 shows the relation between the two-stage combustion rate [(air quantity through burner throat/theoretical air quantity) x 100] and the concentration of NO_x, as compared with a conventional circular burner and the dual air register). Assuming the concentration of NO_x when using only a circular burner as 100%, the reduction rate was 31% by conducting two stage combustion, 39% by the adoption of the dual register alone and 63% by combining the two.

RESULT OF BURNING TEST OF LOW NO_x BURNER (P.G. DUAL AIR REGISTER)

For further reducing NO_x from dual air register burners , the following methods are required.

- (1) Further cooling the flame.
- (2) Decreasing oxygen content at burner.

For the above reason, primary gas port addition to the low NO_x burner is developed.

Figure 26 shows the NO_x test results of adopting 2 stage combustion method and flue gas mixing method for lowering NO_x generation.

The NO_x content is set as 100% (NO_x 400 ppm at 6% O₂) using domestic coal (Low Nitrogen Coal) with dual air register but without 2 stage combustion and flue gas mixing. The NO_x lowering ratio is about 75% by adopting 2 stage combustion and flue gas mixing method using P.G. dual air register. Thus, the NO_x lowering effect of P.G. dual air register was confirmed.

Following table shows the combustion test conditions at the manufacturer's test facility:

Type of coal		Japanese coal	Overseas coal			
			A	B	C	
Proximate analysis	HHV (Dry base)	kcal/kg	6,040	6,494	6,900	6,970
	Moisture	%	1.90	2.04	2.60	3.60
	Volatile matter	%	32.29	25.64	28.20	32.10
	Fixed carbon	%	40.91	55.74	57.30	53.10
	Ash	%	24.90	16.58	12.00	11.10
	Total sulphur	%	1.0	0.83	0.70	0.52
Ultimate analysis	Carbon	%	59.86	67.76	71.98	69.30
	Hydrogen	%	4.08	3.53	4.12	4.50
	Nitrogen	%	1.09	1.61	0.90	1.60
	Oxygen	%	8.07	8.41	10.02	12.60
	Sulphur	%	0.64	0.63	0.42	0.50
	Fluorine	ppm	106	1,681	—	—

1. Furnace
 - Type: Horizontal water-cooled cylinder
 - Size: Inner dia. 2.2m
 - Length 9.0m
 - Combustion capacity : Max. 13x10⁴ kcal/h
2. Type of register
 - (1) Dual air register
 - (2) P.G. Dual air register
3. Type of coal
 - (1) Japanese coal : 1,000kg/h
 - (2) Overseas coal A : 930kg/h
 - (3) Overseas coal B : 870kg/h
 - (4) Overseas coal C : 670kg/h
4. Air temperature : 300 °C
5. Furnace outlet : O₂ 3.0%
6. Fuel analysis

IN-FURNACE DE-NO_x PROCESS

The development of in-furnace De-NO_x process in Japan was originated by Mitsubishi Heavy Industry Co., Ltd. who conducted laboratory scale tests around 1975. In 1978 Tokyo Electric Power Co., Ltd. developed a keen interest in this process, and has carried out research and development work together with Japanese boiler manufacturers. The result of this research work was reported by Mitsubishi Heavy Industry in the United States, and a further report will be presented in this symposium. In this Section, EPCD's comment on the in-furnace De-NO_x technology, based on available data, will be explained.

PRINCIPLE OF IN-FURNACE DE-NO_x PROCESS

Although there is no established theory on the de-NO_x process, the possible principle considered at this moment is that without using reducing agent such as ammonia the produced NO_x is reduced within the furnace by reducing effect of intermediates produced during combustion.

Table 8 shows the outline of such principle, but this explains only one way of thinking.

IN-FURNACE DE-NO_x SYSTEM

In coal firing boiler, coal injecting equipment is installed between the burners and OFA ports. Figure 27 shows the concept of this system.

EVALUATION OF IN-FURNACE DE-NO_x PROCESS

Because of possible further 50% reduction of NO_x emission below the level achieved by conventional combustion modification, this technology draws wide interest.

Table 9 shows a simple comparison of conventional combustion modification and in-furnace De-NO_x process. For instance, when the NO_x level is lowered to 200 ppm by conventional combustion modification technology, it is expected to become 100 ppm by application of this in-furnace De-NO_x process. In some cases installment of SCR would become unnecessary, and detrimental effects to the boiler down stream equipment can be avoided.

The adverse effects caused by installment of SCR are summarized as follows.

- o Plugging of A/H
- o Increase of N concentration of wet FGD equipment
- o Introduction of ammonia into cold-side ESP
- o Vibration of fans (IDF, BUF)

The merit of in-furnace De-NO_x process would be increase of equipment reliability compared to using SCR, but our company has no intention to introduce this process at this moment. We are evaluating it carefully.

ACTUAL BOILER TEST OF SIMILAR IN-FURNACE DE-NO_x PROCESS

With reference to the principle of in-furnace De-NO_x process, EDPC conducted a test on the possibility of a similar in-furnace De-NO_x system at one of the coal fired power stations by cutting the air of upper burners. This was intended to create a small reducing atmosphere within the furnace. The NO_x generation was slightly decreased, RH temperature become higher and slagging was increased in comparison with the present conditions, and the test was suspended. The

application of this process to the existing thermal power plant would be difficult except for some suitable boilers having sufficient inside furnace volume. However, it would be important to investigate the application to existing thermal power plants after the development of this technology is completed.

CONCLUSION

The combustion modification technologies for NO_x control have been developed at test furnaces, and, at present, the results are applied to the newly-built thermal power stations.

For further reduction of NO_x , De- NO_x technology by SCR is now at the commercial stage, and the combination of combustion modification and SCR becomes popular for the construction of coal thermal power plant. The items to be investigated from now on would be as follows.

- o Availability and economy of infurnace De- NO_x technology
- o Automatic combustion control system for safe operation of De- NO_x systems

ACKNOWLEDGEMENTS

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Table 1 Boiler Design Condition

Type	Mitsubishi-CE Sultaw combined circulation boiler
	SCRR radiant reheater (indoor)
Steam flow	
Main steam (MCR)	1,840,000 kg/h
Steam pressure	
Design pressure (Superheater outlet)	268 kg/cm ² g
SHO operating pressure (MCR)	255 kg/cm ² g
Steam temperature	
SHO (MCR)	543 °C
RHO (MCR)	541 °C
Feed water temperature	
Eco. inlet (MCR)	296.6 °C
Air temperature	
Ambient	20 °C
PDF inlet	40 °C
Exit gas temperature	
Eco. outlet (MCR)	380 °C
Air heater inlet (MCR)	370 °C
Air heater outlet (MCR)	130 °C (Corrected)
Fuel firing system	Direct unit system of pulverized coal firing (Pressurized Mill System)
Drafting system	Balanced draft system
Primary air system	Cold primary air fan system

TABLE 2 ANALYSIS OF DESIGN COALS

Nation Coal Mine		Australia	China		Japan	South Africa		
Item		A Coal (Invisible)	A Coal (Waipen)	B Coal (Tatung)	A Coal (Mitsui)	B Coal (Kyushu)	Y Coal (Witbank)	
Heating Value (Moist Coal)	kcal/kg	6,600	6,430	7,100	6,100	5,800	6,400	
Surface Moisture	%	7	7	7	7	7	7	
Inherent Moisture	%	2.7	2.0	2.8	1.6	1.5	2.5	
Proximate Analysis	Ash	%	16.6	19.9	9.9	26.5	26.0	16.0
	Volatile Matter	%	32.6	27.5	28.5	36.7	34.0	25.2
	Fixed Carbon	%	48.1	50.6	58.8	35.2	38.5	56.3
Fuel Ratio	—	1.5	1.8	2.0	1.0	1.1	—	
Total Sulfur	%	0.6	0.3	0.8	3.0	1.3	0.7	
Cl	%	0.08	0.08	—	0.12	0.10	—	
Ultimate Analysis	Carbon, C	%	68.8	67.2	73.8	60.3	58.1	70.4
	Hydrogen, H	%	4.1	3.5	4.0	4.3	4.5	4.2
	Nitrogen, N	%	1.6	1.1	0.8	0.8	1.0	1.7
	Oxygen, O	%	7.8	7.8	11.0	5.4	8.8	6.9
	Sulfur (combustible)	%	0.6	0.1	0.2	2.3	1.2	—
Grindability	HGI	42	6.8	51	52	44	54 - 72	
Ash Softening Temp.	C	1,330	1,320	1,210	1,120	1,410	1,349	
Ash Fusion Temp.	C	1,430	1,480	1,260	1,260	1,450	1,300 - 1,449	

TABLE 3 SPECIFICATION OF BOILER EQUIPMENTS

Boiler Type		Mitsubishi-CE-Sulzer combined circulation boiler
Furnace Type		Fusion welded wall water cooled hopper
" Dimensions		(Width)15,797.5mm x (depth)14,516.5mm x (Height)55,790mm
" Volume		10,700 m ³
" Heat Release Rate		97,940 Kcal/m ³ h
" Heating Surface		6,630 m ²
SH Type		Panel, Platen, Pendant
" Heating Surface		8,070 m ²
RH Type		Platen, Pendant
" Heating Surface		9,200 m ²
ECO Type		Spirally fined tube
" Heating Surface		26,100 m ²
AH Type		Regenerative trisector type (vertical)
" Numbers		1 Unit
" Heating Surface		104,280 m ²
BCP Type		Submerged motor type (Hayward tyler type)
" Number		2 Units (includes 1 spair)
" Capacity (per 1 unit)		1,770 m ³ /h x 80 m x 500 kW
Clinker Hopper Type		W shape-inner lining-water seal type
" Capacity		159 m ³
Sootblower Type		Mitsubishi Vulcan automatic sequential control electrically operated air blowing type
Furnace (Front Wall)		30 Units
" (Rear Wall)		30 Units
" (Side Wall)		50 Units
" (De-Arch)		2 Units
Superheater		16 Units
Reheater		12 Units
Economizer		2 Units
Air Heater		1 Unit
FDF Type		Controllable pitch single stage axial flow type
" Numbers		2 Units
" Capacity (per 1 unit)		17,800 m ³ /min x 640 mmWC x 2,500 kW
IDF Type		Controllable pitch double stages axial flow type
" Numbers		2 Units
" Capacity (per 1 unit)		25,800 m ³ /min x 775 mmWC x 4,120 kW
GRF Type		Double inlet air foil blade centrifugal type
" Numbers		2 Units
" Capacity (per 1 unit)		6,650 m ³ /min x 395 mmWC x 700 kW
SGRF Type		Double inlet air foil blade centrifugal type
" Numbers		1 Unit
" Capacity (per 1 unit)		11,700 m ³ /min x 540 mmWC x 1,450 kW
PAF Type		Double inlet air foil blade centrifugal type
" Numbers		2 Units
" Capacity (per 1 unit)		5,600 m ³ /min x 1,000 mmWC x 1,250 kW
Mill Type		Unit direct pressurized Mitsubishi-CE Bowl mill 943 RP type
" Numbers		6 Units (1 includes)
" Capacity (per 1 unit)		45.3 t/h x 450 kW
Coal HHV		6,200 Kcal/kg
Moisture		10 %
Fixed Carbon		4 %
Grindability		40 HGI
200 mesh thru		More than 70 %

TABLE 4 GENERATED ENERGY

	Unit	No. 1 unit	No. 2 unit
Period		1981.1.16 ~ 1982.1.16	1981.6.19 ~ 1982.3.31
Generation time	H	8,542.72	8,754.50
Starting times	time	3	1
Operation time	Day	358	283
Generated energy	MWH	4,052,862	3,216,290
Auxiliary power ratio	%	6.9	6.4
Availability	%	92.3	93.9
Mixed fuel burning ratio	%	1.6	1.7
Thermal efficiency			
Gross	%	39.34	39.75
Net	%	36.85	37.22
Trouble-caused suspension of operation	time	1	0
Normal suspension of operation	time	2	1

Note: The "Availability" above is not relevant to the time required for regular inspection.

TABLE 5 ANALYSIS OF COALS

Nation - Coal Mine		China			Australia		South Africa		America	Japan
		Waipei	Tatung	Fushin	Miller Blend	Witbank	Elmoro	Plataau	Ikeshima	
Heating Value (Moist Coal)	kcal/kg	5,980	6,010	6,010	6,250	6,430	6,490	6,650	5,920	
Surface Moisture	%	4.7	5.3	9.9	5.9	5.2	6.5	4.7	4.8	
Inherent Moisture	%	2.2	3.7	9.5	3.2	3.3	3.8	5.4	1.9	
Proximate Analysis	Ash	%	24.0	10.2	12.4	20.8	15.6	14.2	9.5	25.4
	Volatile Matter	%	26.3	27.2	31.5	30.6	24.7	28.2	38.0	33.6
	Fixed Carbon	%	47.5	58.9	46.6	45.6	56.4	58.6	47.1	38.1
Total Sulfur	%	0.30	0.80	0.60	0.52	0.93	1.10	0.70	0.89	
Fuel Ratio	—	1.81	2.17	1.48	1.49	2.23	2.05	1.24	1.13	
Ultimate Analysis	Carbon, C	%	63.8	76.0	69.8	65.9	70.8	70.6	72.2	60.6
	Hydrogen, H	%	3.9	4.5	4.4	4.6	4.7	4.2	5.2	4.6
	Nitrogen, N	%	1.1	0.9	0.9	1.6	1.7	1.8	1.5	1.1
	Oxygen, O	%	6.5	7.2	10.6	6.2	5.9	7.8	10.6	6.7
	Sulfur, S	%	0.2	0.8	0.6	0.5	0.8	0.8	0.5	0.7
Grindability	HGI	75	55	53	51	60	80	60	50	
Ash Fusion Temp.	°C	>1,450	1,360	1,180	>1,450	1,410	>1,410	1,310	>1,450	

TABLE 6 NOX AND UNBURNT CARBON IN ASH OF VARIOUS COAL

Load: 500 MW

Kind of Coal	Predicted		Test Results		N Content (%)	Fuel Ratio
	NOx (ppm)	Unburnt Carbon (in Ash (%))	NOx (ppm)	Unburnt Carbon in Ash (%)		
Chinese Coal (Tatung)	< 280	< 5	280 ~ 260	< 4	0.8	2.17
Australian Coal (Miller Blend)	< 280	< 5	260 ~ 240	< 2	1.6	1.55
South African Coal (Witbank)	< 290	< 5	290 ~ 270	< 4.5	1.7	2.17
South African Coal (Elmero)	—	—	260 ~ 240	< 3	1.8	1.82
American Coal (Plateau)	—	—	240 ~ 220	< 2	1.4	1.12
Japanese Coal (Ikeshima)	< 280	< 5	240 ~ 220	< 2	1.0	1.08

Note: The unburnt carbon in ash of Ikeshima coal and Plateau coal was measured when pulverized coal fineness is rough.

TABLE 7 BEHAVIOR OF FURNACE WALL METAL TEMPERATURE AND DESCRIPTION OF FURNACE ASH DEPOSITES

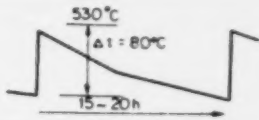
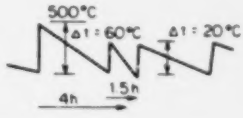
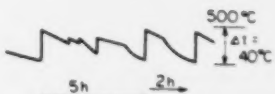
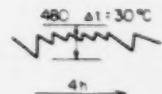
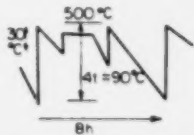
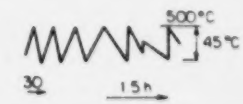
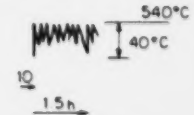
Coal	Behavior of Furnace Wall Metal Temperature	Description of Furnace Ash deposits
Tatung		Furnace ash deposited little by little as ash contents in coal were few. Ash deposits were falled of itself in a period of 15 ~ 20 hours. The thickness of ash deposits was rather think. ($t \approx 80^\circ\text{C}$)
Elmero		Furnace ash deposited rather fast as ash contents in coal and Na ₂ O in ash were rather much, so ash deposits laminated little by little in a period of around two hours ($t \approx 20^\circ\text{C}$).
Witbank		The tendency of slagging characteristics was not remarkable. The thickness of ash deposits was thin and ash deposited all over the furnace. (the thickness of ash deposits was thin. t by sootblowing was around 40°C)
Miller Blend		Furnace ash deposited rather fast as ash contents in coal was rather much. Ash deposits laminated little by little ($t \approx 20^\circ\text{C}$), and in a period of 2 ~ 5 hours ash deposits falled of itself ($t \approx 40^\circ\text{C}$). Thickness of ash deposits was rather thin.
Rietspruit		The tendency of ash deposits resembled to that of witbank coal except that ash deposited rather much than witbank coal.
Rietspruit(70%) + Elmero(30%)		The tendency of slagging characteristics was stronger than that of individual firing. Ash deposited and laminated in a period of around two hours and falled of itself in a period of 8 hours. The thickness of ash deposits was rather think ($t \approx 90^\circ\text{C}$)
Tatung (50%) + Ikeshima(50%)		The tendency of ash deposits resembled to that of Ikeshima coal. Thickness of ash deposits was thin as ash deposited and laminated in a short period.
Fushin (70%) + Plateau (30%)		In case of platen coal ash deposits laminated in a short period as ash fusion temperature was low. In case of combination firing with Fushi coal, the tendency of ash deposits resembled to that of plateau coal. The thickness of ash deposits was rather thin ($t \approx 40^\circ\text{C}$)

Table 8 Outline of In-furnace DeNO_x Principle

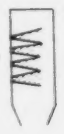
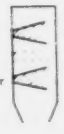
	A	B	C
Concept Figure			
Explanation	1 Complete Combustion Carbon, CO are combusted completely $2C + O_2 \rightarrow 2CO_2$ 2 Reduction Radical material Injection to reduce NO_x $NO_x + H_2 \rightarrow N_2 + H_2O$ 3 Main Combustion Conc/weak Combustion reduce NO_x	1 Complete Combustion CH compound, CO are combusted completely 2 Reduction CH compound generated and it react to reduce NO_x $CnH_m + NO \rightarrow CO + N_2 + H_2O$ 3 Over fire air CO, CH compound and combusted to CO₂ H₂O 4 Main combustion Thermal NO_x, CH compound generated	1 Complete Combustion Air is injected and fuel is combusted completely 2 Reduction Reduction Material Such as CO, H₂, C, etc. reduce NO_x 3 Main Combustion Reduction material produced (fuel rich zone)

Table 9 Comparison of Conventional Combustion Modification and In-furnace De-NO_x Process

Items	Conventional Combustion Improvement	In-furnace De-NO _x process
1. Low NO _x burner	Yes	Yes
2. 2-Stage combustion	Yes	Yes
3. Gas mixing	Yes	Yes
4. Additional upper burner	None	Yes
5. Height of boiler	Base	20%-30% higher
6. CH 2	Base	1.5 to 2 times
7. After air	None	Yes
8. Systems such as mills for additional upper burner	None	Yes
9. Heat efficiency	Base	Same
10. NO _x reduction	Base	Up to 50% (Expected value)
11. Unburned carbon	Base	Same
12. Power	Base	Almost same
13. Following load variation	Base	To be investigated

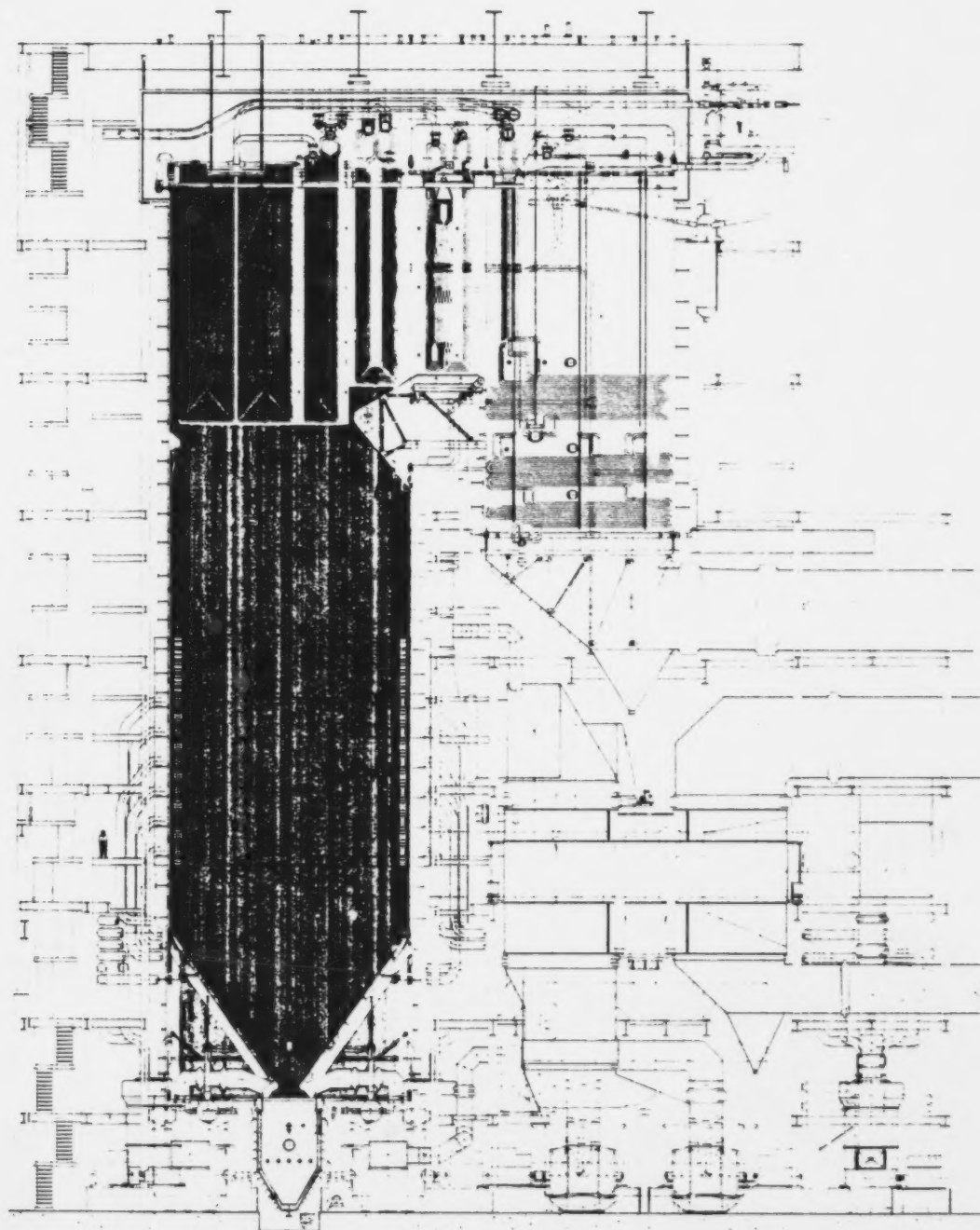


FIG. 1 GENERAL ARRANGEMENT OF MATSUSHIMA NO. 1 & 2 BOILERS (SIDE VIEW)

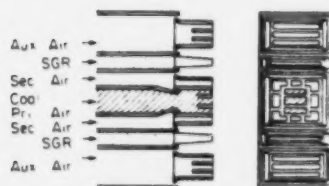
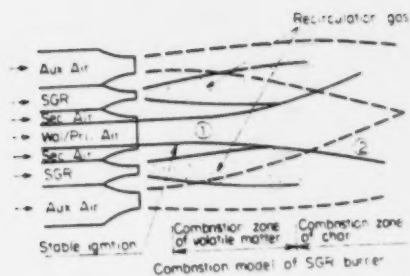


Fig 2 BURNER ARRANGEMENT

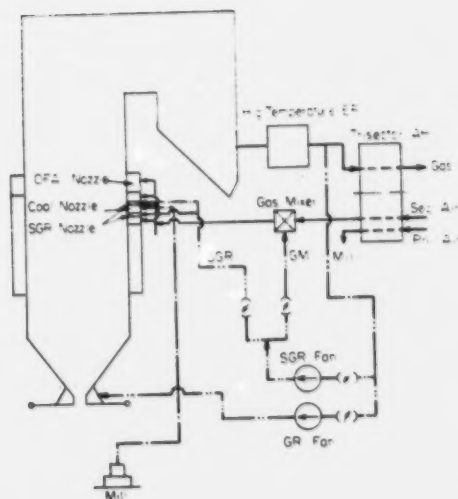


Fig 3 AIR & GAS FLOW DIAGRAM

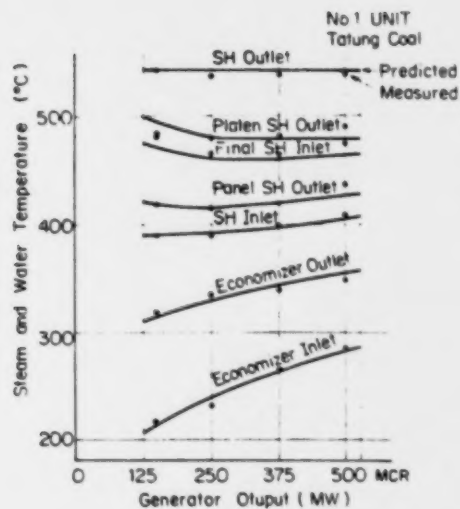


Fig. 4 BOILER STATIC PERFORMANCE
(Steam and Water Temperature)

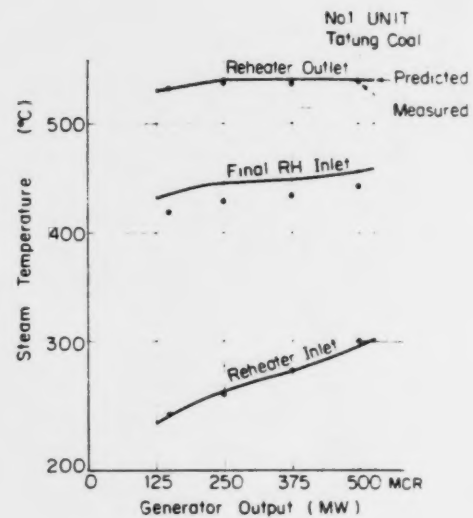


Fig. 5 BOILER STATIC PERFORMANCE
(RH Temperature)

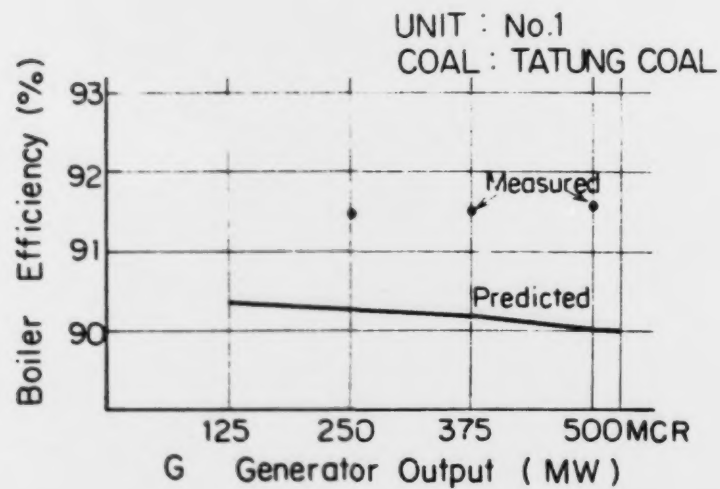


Fig. 6 BOILER EFFICIENCY

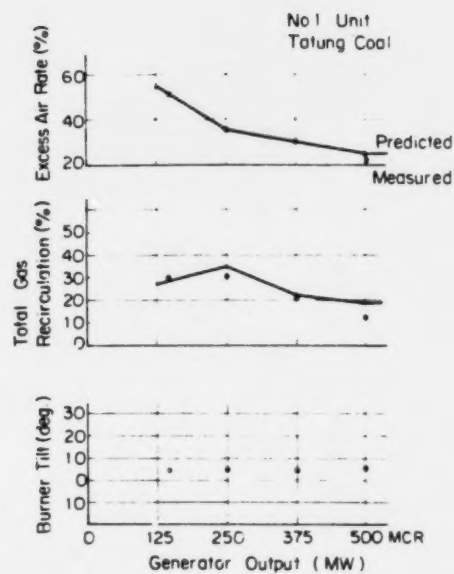


Fig 7 BOILER STATIC PERFORMANCE

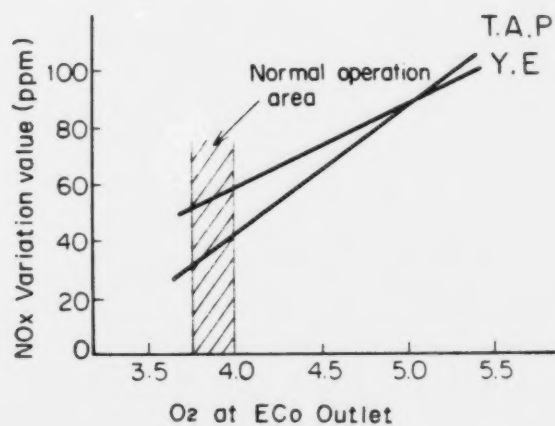


Fig.8 O₂ AT ECO OUTLET VS NO_x VARIATION VAUE

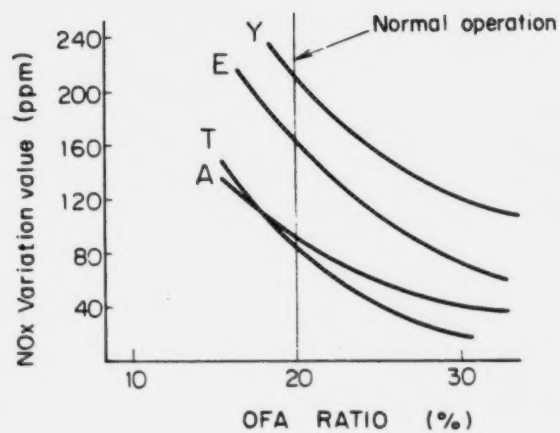


Fig.9 OFA RATIO VS NOx VARIATION VALUE

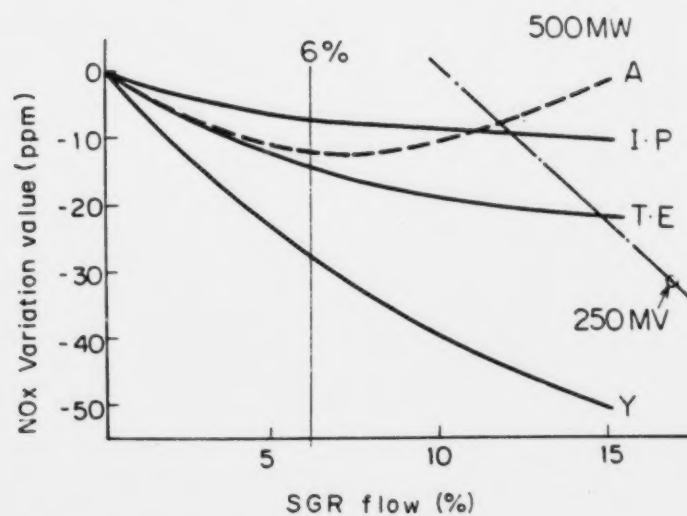


Fig.10 NOx VS SGR Flow

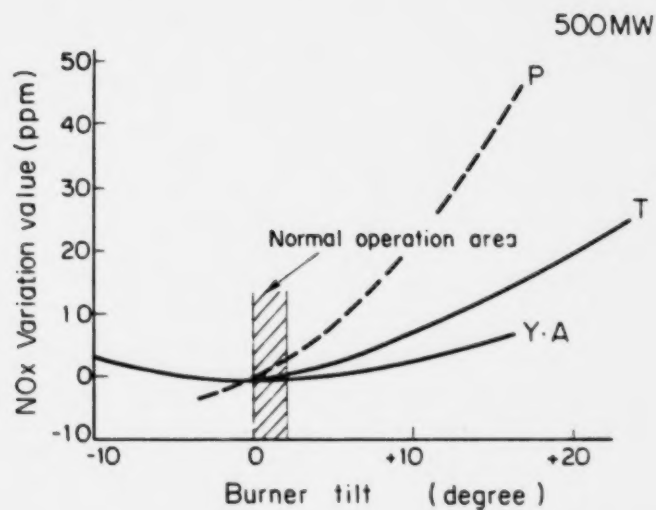


Fig.11 BURNER TILT VS. NO_x EMISSION LEVEL

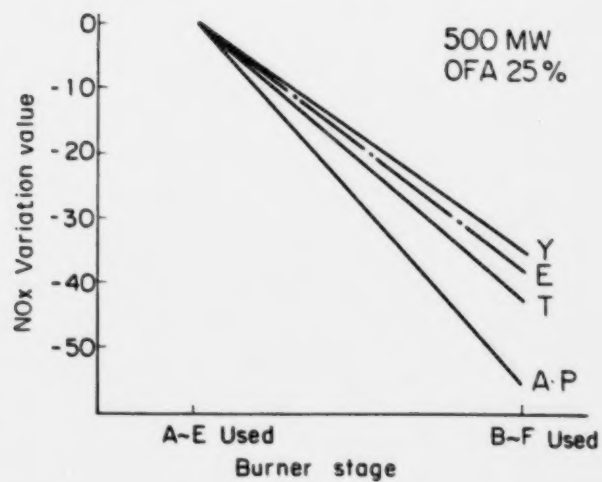


Fig.12 BURNER STAGE VS. NO_x EMISSION LEVEL

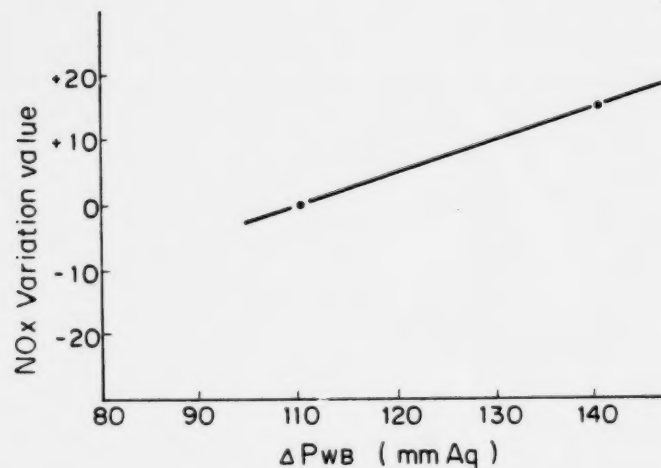


Fig.13 WIND BOX DIFFERENTIAL PRESSURE VS. NO_x EMISSION LEVEL

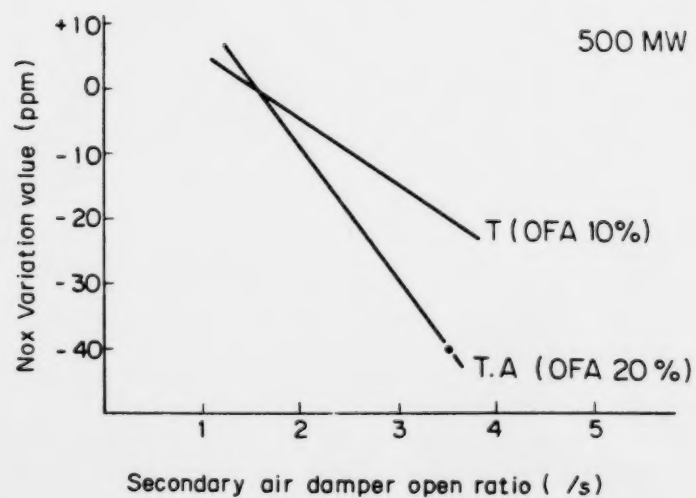


Fig.14 DAMPER OPENING OF SECONDARY AIR VS. NO_x EMISSION LEVEL

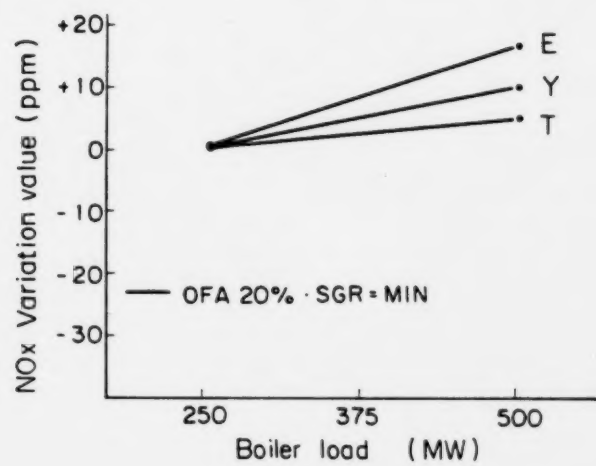


Fig.15 LOAD VS NO_x VARIATION VALUE

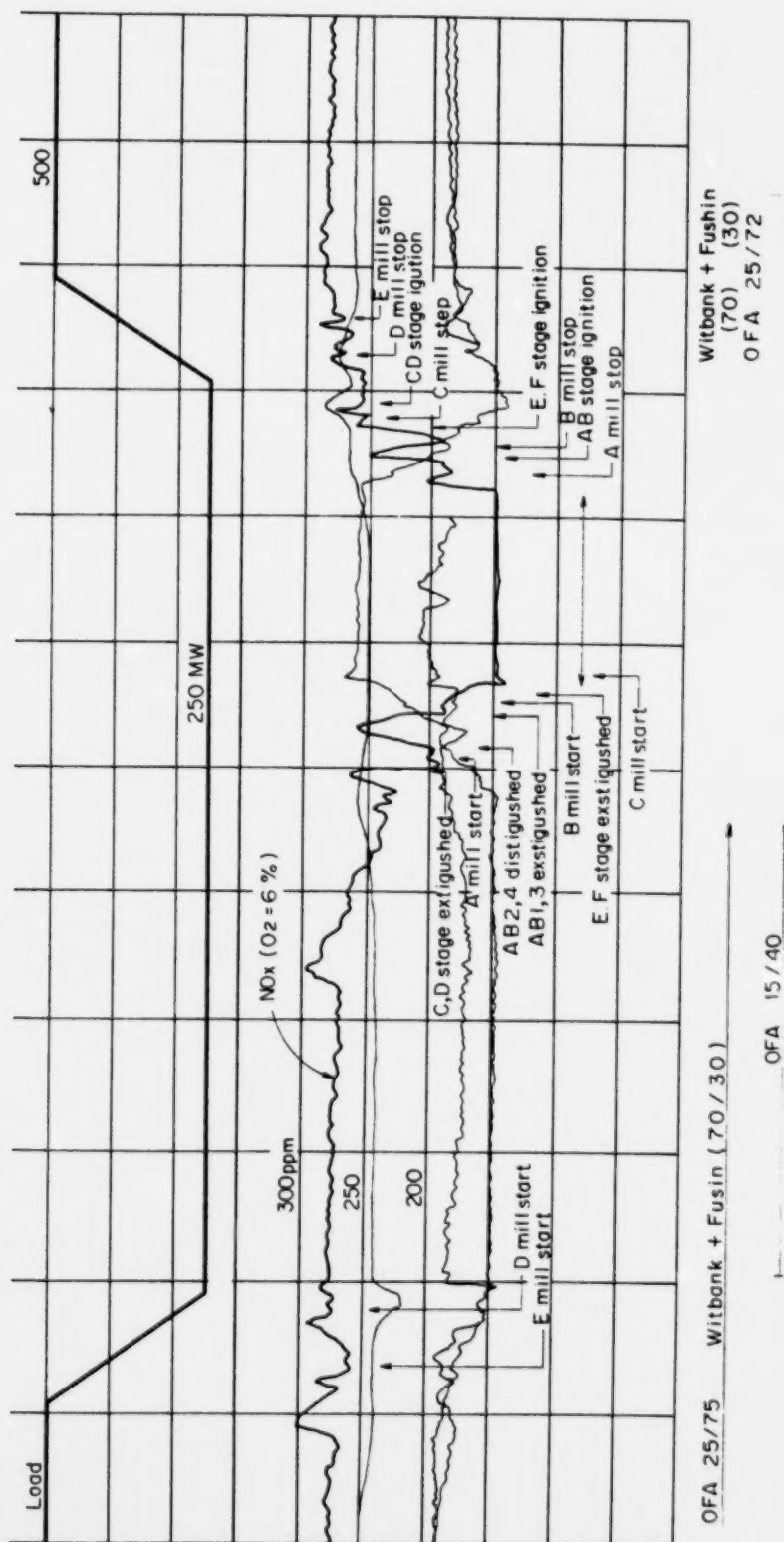


Fig.16 NOx CONCENTRATION IN LOAD CHANGE

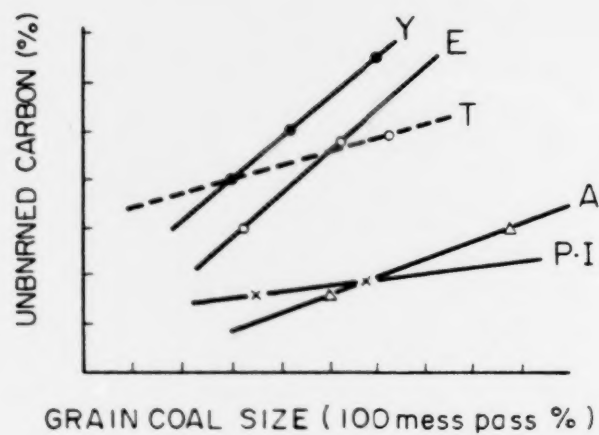


Fig.17 GRAIN COAL SIZE VS UNBURNED CARBON

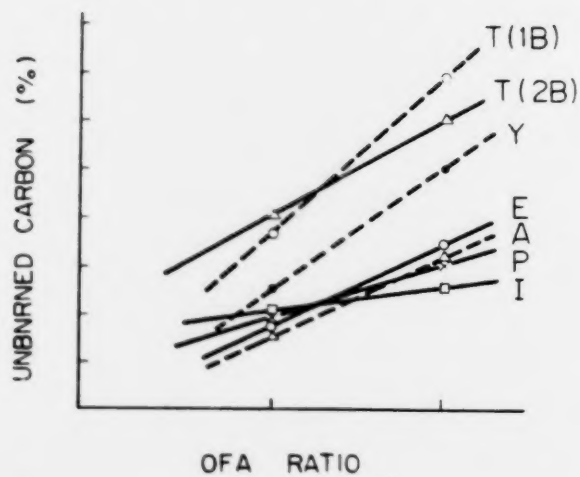


Fig.18 OFA RATIO VS UNBURNED CARBON

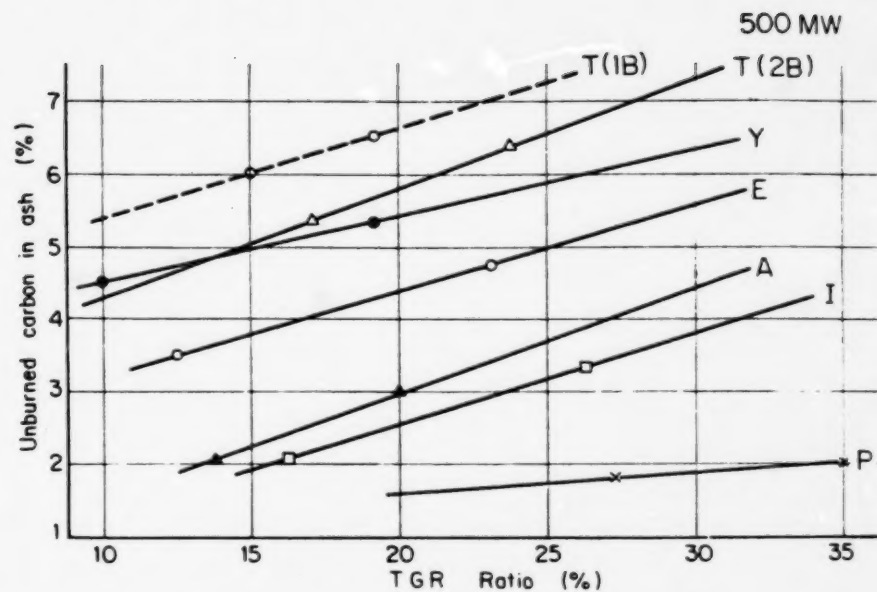


Fig.19 TGR RATIO VS UNBURNED CARBON

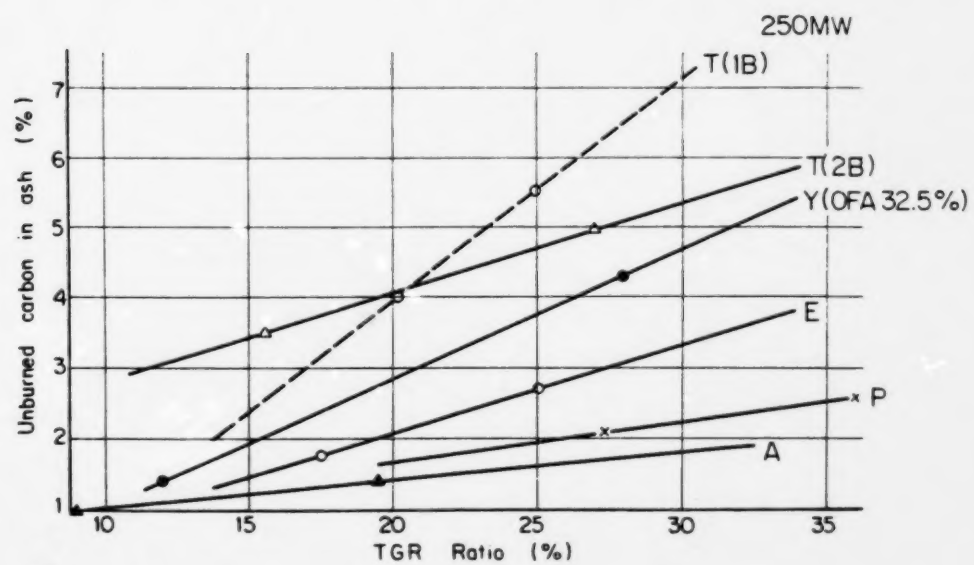


Fig.20 TGR RATIO VS UNBURNED CARBON

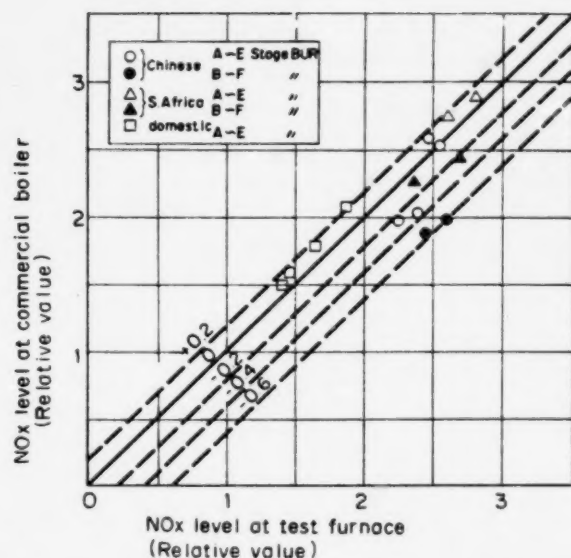


Fig. 21 COMPARISON OF NO_x BETWEEN FIELD TESTS AND LABORATORY TESTS

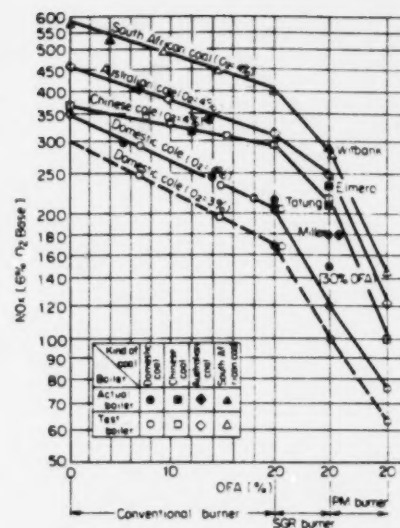


Fig. 22 COMPARISON OF NO_x EMISSION LABORATORY TEST RESULTS VS. FIELD DATA

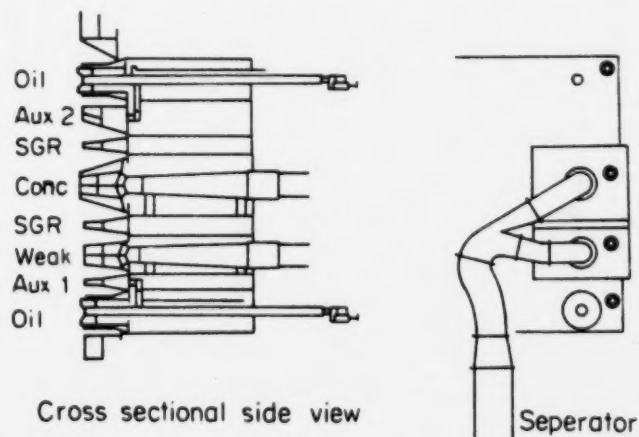


Fig. 23 STRUCTURE OF COAL FIRED LOW-NO_x PM BURNER USED

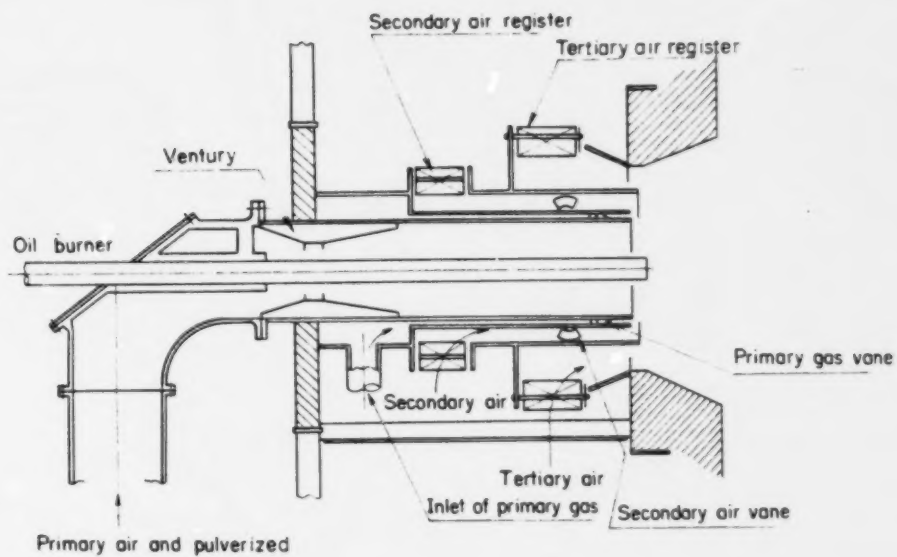


Fig.24 BHK LOW NO_x BURNER

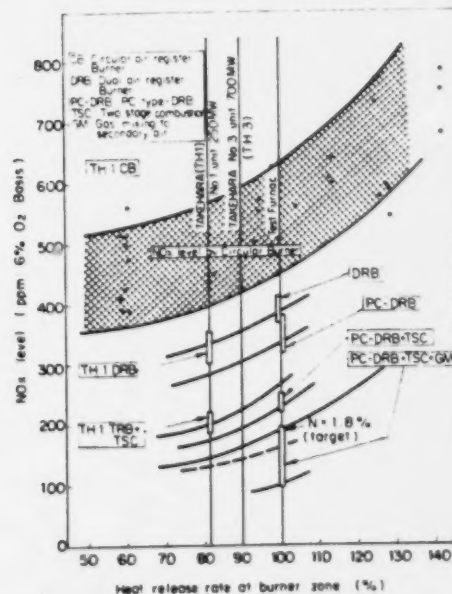


Fig.25 HEAT RELEASE RATE AT BURNER ZONE VS NO_x LEVEL

Burner Type	Coal	No Control	2 stage Combustion	2 stage + GM	2 stage + GM + PG
Dual air register	Japanese coal	×	—	—	—
P.G. Dual air register	Japanese coal	○	◐	●	◉
	Overseas coal A	△	◀	▲	◈
	Overseas coal B	□	◑	■	◐
	Overseas coal C	▽	—	—	▼

Remarks) 1. ◐ Shows that combustion air ratio is different when using 2 stage combustion.
2. GM = Gas mixing in combustion air
3. PG dual air register primary gas air resister

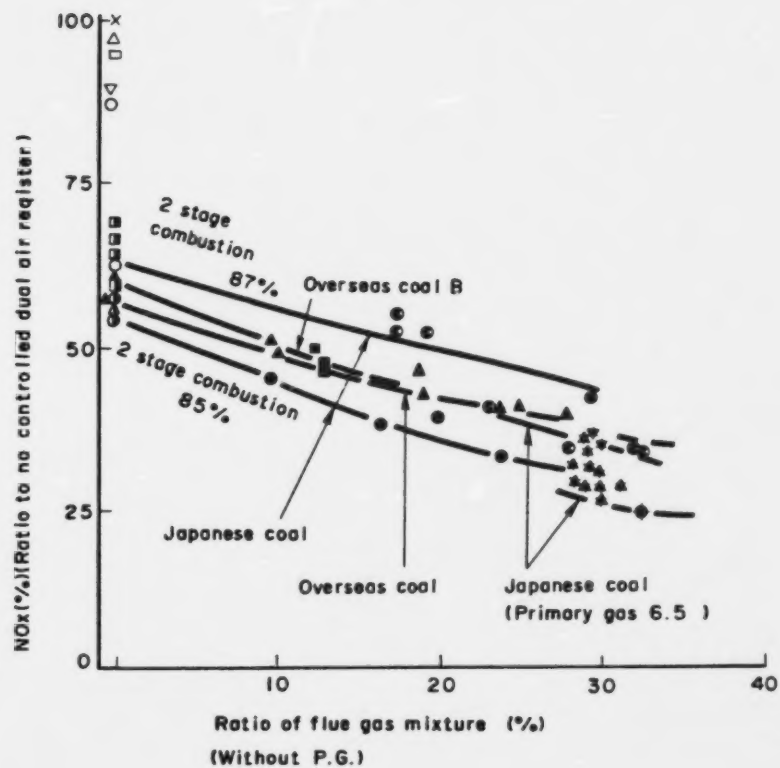


Fig.26 Results of tests on combustion furnace in the works, showing the data obtained by the burning test in the works, of NOx resulted by NOx reduction means.

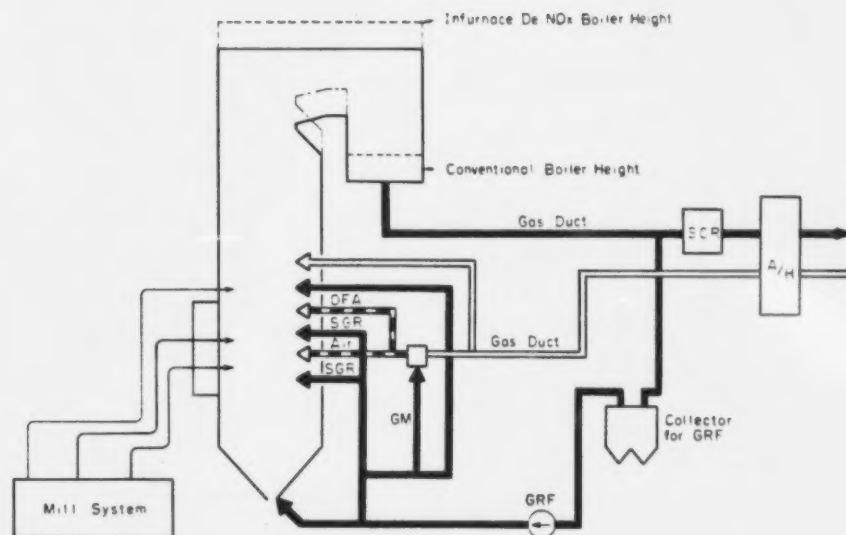


Fig.27 CONCEPT FLOW OF INFURNACE-DE NOx (COAL FIRED)

SESSION V

IN-FURNACE NO_x DESTRUCTION (REBURNING)
Chairman, Michael W. McElroy
EPRI

DEVELOPMENT OF "MACT"
IN-FURNACE NO. REMOVAL PROCESS
FOR STEAM GENERATORS

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ABSTRACT

Mitsubishi Heavy Industries, Ltd. (MHI) of Japan has Developed a new NOx reduction process in the furnace by hydrocarbons, named MACT. The first commercial application has been done in a 125 MW oil-fired boiler and the unit has been operated more than one year. The application for a industrial boiler has also been done in a 280 T/H oil fired boiler. MACT for coal fired boilers has been developed in MHI's test facilities and is ready for commercial application.

INTRODUCTION

NOx reduction technology developed so far will be classified into the following three categories, in which MHI has made great progress.

- 1) Combustion improvement
- 2) Non-catalytic ammonia injection
- 3) Catalytic ammonia injection

As combustion improvement, a low NOx PM burner system has already been established, using offset-premix flame theory. This system has been applied to more than 30 new and retrofitted boilers⁽¹⁾. Generally speaking, in tangentially fired units NOx level of 30 ppm for gas, 80 ppm for oil, 150 ppm for coal have been realized without deteriorating quality of combustion and flue gas.

An ammonia injection system can reduce NOx by a certain ratio regardless of base NOx level, and process efficiency reaches about 80 % if a catalyst is used. However, the cost of ammonia or renewal of catalyst reduces its economy, and the ammonia slip or maintenance of air preheater must be taken care of.

Not satisfied with these technologies, MHI continued its effort to develop an even more efficient and economical system, to meet the needs for environmental protection and energy savings.

The requirements of development are,

- 1) Economy ———— no use of ammonia, or catalysts.
- 2) Safety ———— safe and stable operation must be achieved.
- 3) Clean ———— no harmful secondary gas products in flue gas.
- 4) Efficiency ———— minimum required space (minimum residence time for reaction).
- 5) Flexibility ———— constant effect over a wide load range.
- 6) Applicability ———— available for all fossil fuels and free combination of existing technologies.

As a solution, hydrocarbon injection into the furnace was selected. Numerous basic tests had been carried out in bench-scale and combustion test furnaces.

The new system has been named "MACT" which stands for Mitsubishi Advanced Combustion Technology. To confirm these fundamental tests, MHI started a joint investigation projects with the Tokyo Electric Power Co., Inc. (TEPCO) to finalize the application of MACT to actual boilers using pilot test plants in Nagasaki Technical Institute. The test covered gas, oil and coal using vertical test furnaces with tangential corner firing. These tests have been completed successfully reducing NO_x by 50 % from the low NO_x levels previously achieved. Stable, reliable operation with low NO_x and minimum dust loading was realized. Based upon these encouraging results, actual application of MACT to a 125 MW oil-fired boiler was implemented, and proved excellent performance of MACT just as expected.

The expected minimum NO_x emission levels with low NO_x PM burner plus MACT in new tangentially fired units will be as follows:

GAS	10 - 20 ppm
OIL	40 - 60 ppm
COAL	60 - 100 ppm

For retrofit applications the effect of MACT may sometimes be limited due to existing conditions and amount of expenditure. Now MHI is confident that this new technology will successfully compete with conventional NO_x removal system on both new and retrofit applications if conditions are satisfactory.

FUNDAMENTAL TEST

MACT is basically a decomposition of NO by use of hydrocarbons in a very high temperature zone. The detail of MACT theory is described in another paper⁽²⁾, therefore only the summary is described here.

By a series of tests, using a cylindrical test furnace, the specification and flow chart of which are shown in TABLE 1 and Fig. 1, respectively, it was confirmed that hydrocarbon fuels have two contradictory actions on NO,

- | | |
|--|----------------------|
| 1) Reducing action at high temperature and low O ₂ concentration | NO → N ₂ |
| 2) Oxidizing action at low temperature and high O ₂ concentration | NO → NO ₂ |

Change in NO for various temperature and O₂ conditions are shown in Figs. 2 and 3, and summarized in Fig. 4. These figures suggest the

promising possibility of in-furnace NO_x reduction by hydrocarbons in steam generators, namely, high combustion temperature and low excess air are inherently achieved in the combustion chamber.

In addition, various characteristics of the reduction of NO by means of fuel were disclosed from the basic reaction test with reaction tube. The data have been remarkably useful for establishing optimum design of the MACT in-furnace NO_x removal process. Fig. 5 shows one of the test apparatus consisting of two-stage reaction tubes, and desired atmosphere and temperature can be obtained in each tube.

Reduction of NO by MACT is divided in two stages, (1) decomposition of NO (DN process) and (2) completion of combustion of secondary fuel (AA process).

During the DN process, most of the NO is decomposed and in the AA process, some part of the decomposed products are turned to NO again, and overall NO reduction efficiency (approximately same as NO_x reduction efficiency) is 50 % or more in a certain condition.

The influences of reaction temperature, NO concentration, residence time and air ratio λ on NO decomposition during DN process are shown in Figs. 6, 7, 8 and 9, respectively.

From the fundamental tests, it was found that the following conditions are required for better MACT reaction.

- 1) Higher reaction temperature is desirable (preferably above 1,200 °C).
- 2) Required residence time must be greater than 0.1 sec.
- 3) Reduction efficiency is independent of inlet NO level.

SCALE MODEL TEST

With these favorable conditions for large size utility steam generators, MHI and TEPCO jointly performed combustion tests for gas, oil and coal firing using vertical test furnaces with tangential firing, and obtained excellent results just as the fundamental tests had predicted. One of the test furnaces, which is a pulverized coal fired furnace is shown in Fig. 10 and TABLE 2.

Since the NO_x products in the flue gas depends on the excess air in combustion, the NO_x removal effect is well exhibited by comparing the O₂ - NO_x curve for main burner only with that for MACT. Figs. 11, 12 and 13 correspond to gas, heavy fuel oil and pulverized coal firing, respectively.

Irrespective of fuel used, the NO_x level in main burner is lowered by about 50 %. The minimum values of NO_x concentration achieved by the application of MACT with the main burner under low-NO_x operation, are 8, 35 and

55 ppm at O₂ concentration 1, 1 and 4 %, respectively (The NO_x values are corrected to 5, 4 and 6 % O₂, for gas, heavy fuel oil and pulverized coal firings, respectively, according to Japanese Environmental Protection Regulation).

Because the MACT process is a completely new NO_x removal system, a complete investigation into potentially harmful compounds in flue gas was performed. Based on these results, it was confirmed that the NO_x content in the exhaust gas with MACT operation is approximately 50 % of that in the exhaust gas of the conventional low NO_x operation without MACT (with OFA and Gas Mixing methods, etc.) and no harmful components were produced by the MACT process.

Also based on the analysis result of unburnt combustibles in fly ash and on the amount of dust loading, it is evident that the MACT process does not deteriorate combustion.

MACT process also has a good dynamic response. With the introduction of secondary fuel as the denitrification agent and additional air, the NO_x level at furnace drops sharply, which is also a great advantage in applying MACT to actual steam generators.

ADDITIONAL TEST ON COAL

In a series of previous tests, domestic coal: Taiheiyo coal was used and overall NO_x reduction efficiency was as high as the other hydrocarbons such as gas and oil. Considering the available coals to Japanese modern power stations, it is necessary to test various imported coals, which usually produces higher NO_x emission because Nitrogen content and fuel ratio (FC/VM) is higher.

Among the various coals characterized in NO_x emission, three coals and one char which analysis are shown in TABLE 3 were tested. The results of NO_x reduction efficiency are summarized in relative value as shown in Fig. 14.

Analyzing these NO_x reduction efficiency and characteristics of coals, it is understood that if fuel ratio (FC/VM) becomes higher, NO_x reduction efficiency in DN process becomes lower and if Nitrogen content becomes higher, NO_x production in AA process becomes higher, thus overall NO_x reduction efficiency is mainly influenced by these two major characteristics of coal.

MACT SYSTEM

The MACT in-furnace DeNO_x system consists of a main burner, upper fuel injector for the DeNO_x process, and additional air port for completing combustion. A typical layout of upper fuel injector (UFI) and additional air (AA) is shown in Fig. 15 in comparison with the conventional OFA (overfire air) system. Fig. 16 shows an illustration of MACT system

including flue gas recirculation. Part of the main fuel is separated from the main fuel line and injected through the upper fuel injector. Recirculated flue gas from the economizer outlet, instead of ordinary combustion air, is introduced to the upper fuel injector windbox and ejected from the nozzle to carry and mix the injected secondary fuel with the product of combustion from the main burner. NO_x (mostly NO) generated in the main burner zone is decomposed by added fuel in this area. The remaining fuel is combusted completely with the additional air through the AA nozzle, and the flue gas enters into the convective heat transfer zone just like in ordinary boilers. Thus, all the reactions are finished within the furnace and furnace overall heat absorption remains almost unchanged. Therefore, there is generally no need to change superheaters, reheaters, economizer and air preheater from the conventional design.

In a pulverized coal fired boiler, reaction speed of coal at main burner zone, DN zone and AA zone largely effects on a NO_x reduction efficiency and required residence time or furnace height, which means it is essential to get better fineness in pulverized coal for better reducing NO_x emission within a reasonable size of a furnace.

When doing a detailed study for the installation of MACT especially in case of retrofit applications, the plant condition must be carefully checked and optimum plan must be established so as to enable maximum effect with minimum cost.

FEATURES OF MACT

MACT in-furnace NO_x reduction system has a number of advantageous features.

1) Applicable to all fossil fuels

Fuel for upper fuel injector can be the same or different from the main fuel.

2) Little additional operating cost

No ammonia needed.

No catalyst used.

No special supervision or skills of operation needed.

3) Reaction is completed within the furnace

NO steel structures and foundations are needed for reactors, thus minimizing required space and capital cost.

4) No emission of additional undesirable substances to the environment

No ammonia slip.

No fear of air preheater pluggage or corrosion.

No harmful products in the flue gas.

5) Boiler efficiency and flue gas quantity unchanged

No need to increase excess air and boiler exit gas temperature. Therefore boiler efficiency remains unchanged.

6) Free combination with other NOx reduction system

Can be combined with low NOx burner, non-catalytic ammonia injection system (MHTT) and selective catalytic reactors (SCR), independently or in combination.

7) Furnace safety is secured

Combustion with MACT is very stable and easy to operate. Flame monitoring with MACT is the same as without MACT.

8) Easy operation and control

Change from non-MACT operation to MACT operation can be done quite easily and excess O₂, steam temperatures, exit gas temperatures, etc. remain almost unchanged while NOx is reduced to almost half.

When MACT condition is established, NOx level is very stable and does not change greatly even if the operating parameters are changed.

MACT operation can be easily monitored by furnace TV. Fig. 17 shows combustion in furnace seen from top through furnace TV without MACT operation, and a fireball can clearly be observed. Fig. 18 shows operation with MACT with extremely low NOx level, and it seems as if a dense "screen" covers the furnace. This is because the TV looks at the fireball through a NOx decomposing layer. Some operator calls this layer a "MACT Cloud" and commented "It's easy to operate MACT. Just make a 'MACT Cloud', and NOx is reduced instantly". Of course, under the cloud, a brilliant fireball is established and stable combustion is secured.

APPLICATION OF MACT

Based on the successful results at the laboratory, it was decided to go ahead with actual full-scale field application. The design and operation of MACT for steam generator is described here referring to the application of MACT to a 125 MW oil fired boiler⁽³⁾ and industrial oil fired boiler of 280 T/H.

Utility Oil Fired Boiler of 125 MW Unit

Outline of Boiler

Boiler type	Mitsubishi-CE Natural Circulation Radiant Reheat Type
Firing system	Tangential firing with Mitsubishi low NOx PM burner
Draft system	Balanced draft
Unit output	125 MW
Evaporation	435 T/H
Steam press. & temp.	139 kg/cm ² g x 540.5/540.5 °C

Major Modifications for MACT

Major modified parts for application of MACT to an existing oil fired boiler are as follows:

Furnace and burner

Existing main windbox is moved to lower position. Upper fuel injector windbox and additional air windbox are installed above the main burner. Distance between main burner and upper fuel injector, and that of upper fuel injector and additional air are elaborately decided so as to secure sufficient residence time for reaction.

Main burner comprises 12 oil guns (3 stages x 4 corners) of low NOx PM burner. Thus, main burner itself has very low NOx level. Nozzle configuration of single-gun type PM burner is shown in Fig. 19.

Draft system

As a carrier gas of injected fuel from upper fuel injector, part of the gas is extracted from the economizer outlet and introduced to UFI windbox. To obtain sufficient momentum, the recirculated gas is pressurized by a booster fan in the circuit.

Control systems

Basically no change in control system is needed for application of MACT except the control of upper burner fuel, upper recirculated gas flow and additional air flow. Bird's eye view of the boiler after MACT modification is shown in Fig. 20.

Results of Operation

Commercial operation of MACT after retrofit work has been started on February 1, 1981 after one month trial operation.

The results show quite satisfactory performance of MACT, realizing extremely low NO_x level which has never been achieved before without the help of ammonia and catalysts. The results are summarized as follows:

Theory of MACT has been applied for the first time in the world in actual boiler, and proved excellent results as expected from theoretical study and laboratory test.

Extremely low NO_x level has been achieved by the combination of low NO_x PM burner and MACT over a wide load range as shown in Fig. 21. MACT operation is possible even at low load as 30 % MCR. Dust loading at boiler outlet is maintained even with low NO_x operation.

Combustion with MACT is very stable and MACT condition can be easily established. Combustion at main burner zone seems to be even improved.

When MACT condition is established, NO_x level is very stable and does not change greatly even if the operating parameters are changed.

Flame monitoring works quite satisfactorily with MACT operation just same as non-MACT operation.

Change from non-MACT operation to MACT operation can be done quite easily and excess O₂, steam temperatures, exit gas temperatures, etc. remain almost unchanged while NO_x is reduced to almost half.

During the MACT tests, hydrocarbons, ammonia and hydrogen cyanide have been measured and not detected in all test conditions with MACT.

More reduction of NO_x might be achieved by modifying the process of fuel injection with advanced burner atomizer or other methods.

Industrial Oil Fired Boiler of 280 T/H

Outline of Boiler

Boiler type	Mitsubishi-CE Natural Circulation Radiant Type (Bottom support)
Firing system	Fixed tangential firing of conventional oil burner with over fire air plus MACT
Draft system	Pressurized
Evaporation	280 T/H
Steam press. & temp.	120 kg/cm ² g x 541 °C

Design of Boiler

This is the first industrial boiler designed with MACT, which was delivered to oil refinery company in 1982.

Main burners consists of three elevations, four burners at upper level for bunker-C oil, four burners at middle for either bunker-C or refinery oil and at lower elevation four refinery oil burners and four refinery gas burners are installed. Bunker-C oil and recirculated gas are injected through upper fuel injector located above the main burner windbox. AA port is installed above upper fuel injector for complete combustion.

Results of Operation

Commercial operation has been started June, 1982. Boiler is operated with bunker-C oil.

The results show quite satisfactory performance as expected and are summarized as follows:

As shown in Fig. 22, NO_x level is a little bit higher and NO_x reduction efficiency is a little bit lower compared with the performance results of 125 MW. But considering higher NO_x from main burner (PM burner is not installed in this case) and small residence time due to small capacity of boiler or not enough space between main burner and UFI, and UFI and AA, both of NO_x level and NO_x reduction efficiency are reasonable and satisfactory all over the load range.

Combustion with MACT is very stable all over the load range.

Dust loading at boiler outlet was maintained at the same level for either MACT operation or non-MACT operation.

CONCLUSION

The combustion tests with a MACT in-furnace NOx reduction system have been satisfactorily completed on a 125 MW utility oil fired boiler and the boiler has operated with MACT since January, 1981 as introduced. And also in 280 T/H industrial oil fired boiler, MACT in-furnace NOx reduction system has been satisfactorily operated since June, 1982.

MHI recommends the use of MACT technology from both aspects, better environmental protection and minimum operating cost where necessary to meet existing regulations.

The expected minimum NOx emission level with low NOx PM burner plus MACT in new tangentially fired units is as follows:

GAS	10 - 20 ppm
OIL	40 - 60 ppm
COAL	60 - 100 ppm

MHI is now constructing a new 600 MW coal/oil dual fired supercritical units with MACT which is expected to be put into operation in mid-1983.

Application of MACT is under study in a number of new and retrofit jobs to meet the request of environmental protection.

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- (2) Y. Takahashi et al., Development of Mitsubishi "MACT" In-Furnace NOx Removal Process, Presented at the U.S.-Japan NOx Information Exchange, Tokyo, Japan, May 25-31, 1981. Published in Mitsubishi Heavy Industries, Ltd. Technical Review Vol. 18, No. 2 (June 1981).
- (3) Y. Takahashi et al., Development of MACT-In-Furnace NOx Removal Process for Utility Steam Generator, Presented at American Power Conference, Chicago, Illinois, U.S.A., April 26-28, 1982. Published in Volume 44, Proceedings of American Power Conference, 1982.

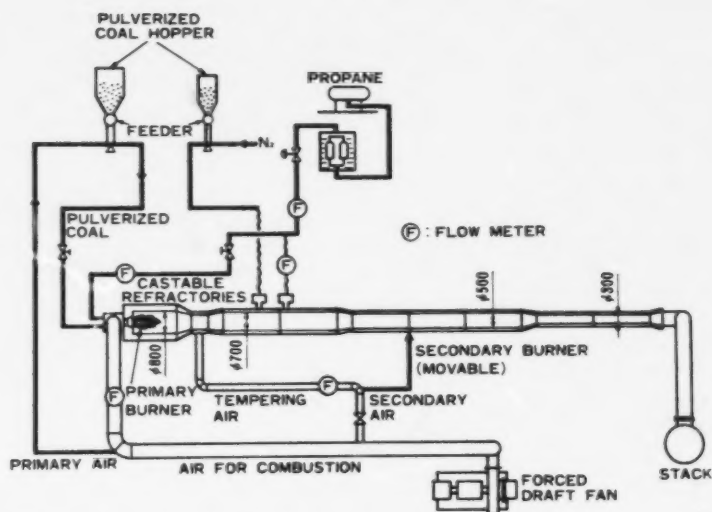


Fig. 1. Flow sheet of cylindrical furnace

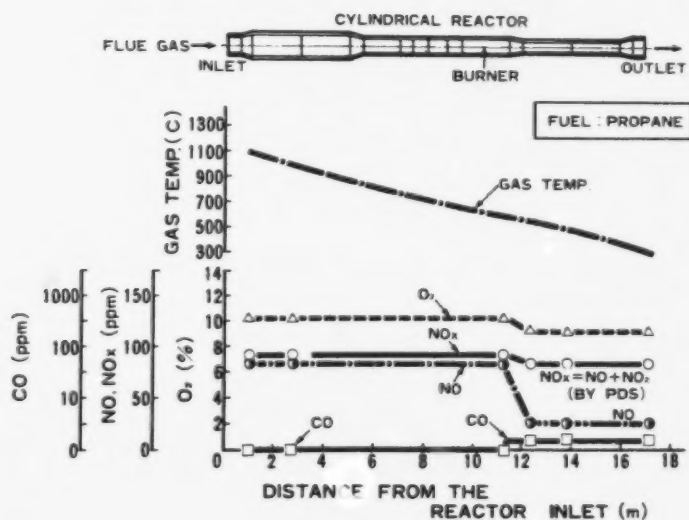


Fig. 2. NO-conversion in NO oxidizing condition

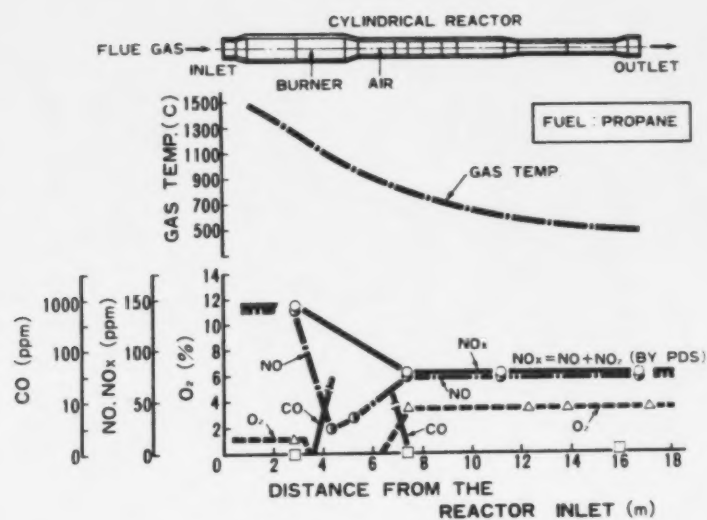


Fig. 3. NO-conversion in NO reducing condition

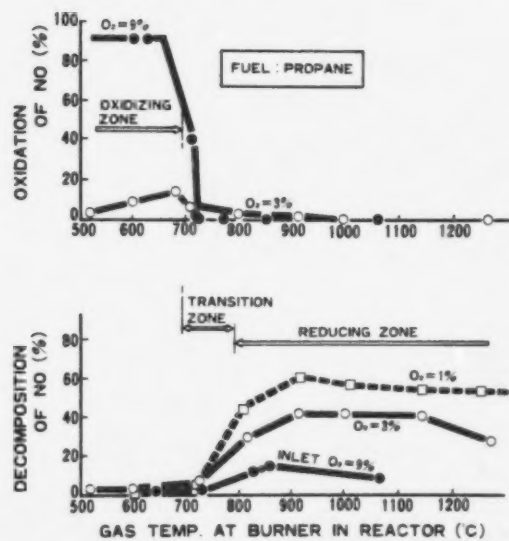


Fig. 4. Oxidizing and reducing regions of NO

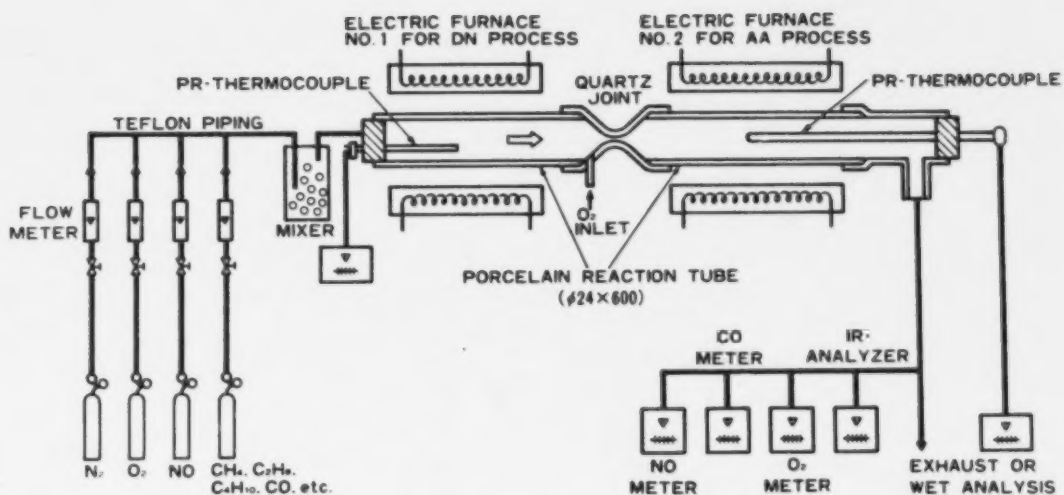


Fig. 5. Flow sheet of testing apparatus

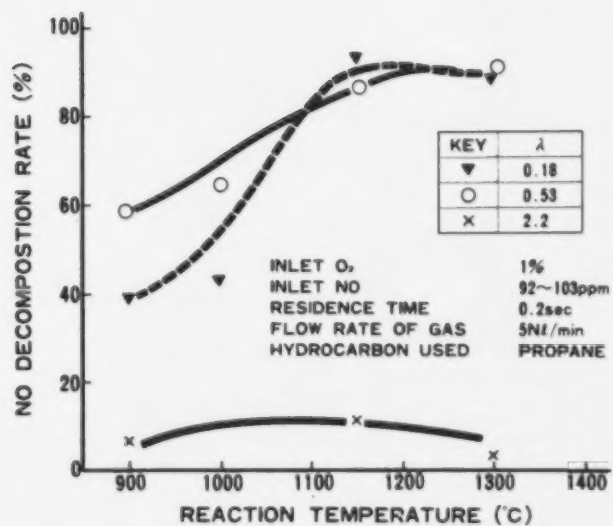


Fig. 6. Influence of reaction temperature on the NO decomposition rate

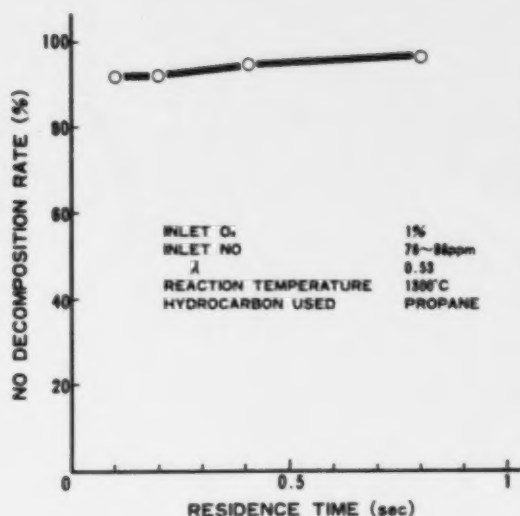


Fig. 7. Influence of residence time on the NO decomposition rate

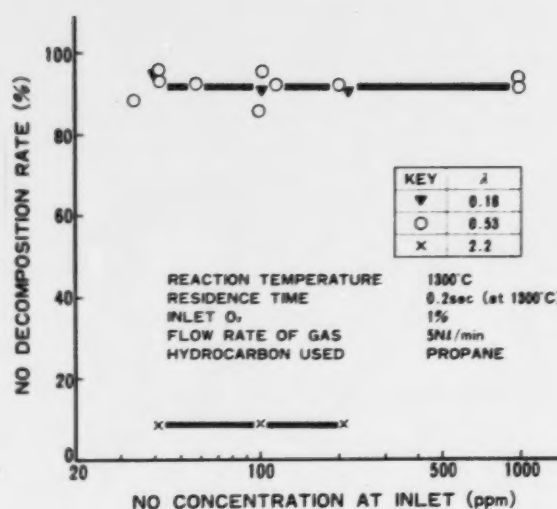


Fig. 8. Influence of inlet NO concentration on the NO decomposition rate

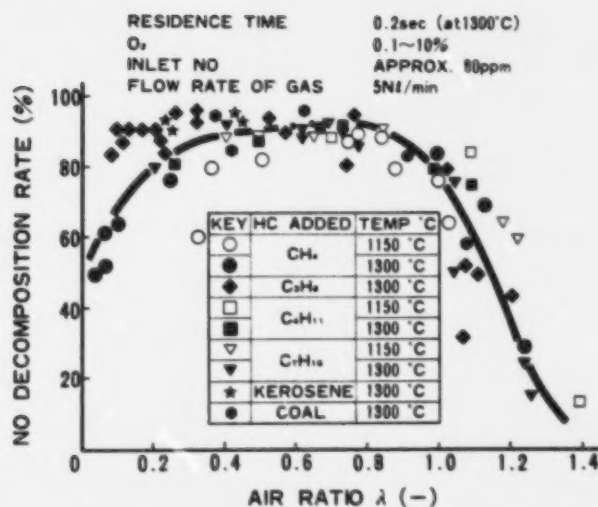


Fig. 9. Influence of air ratio in DN process on the NO decomposition rate for various fuels

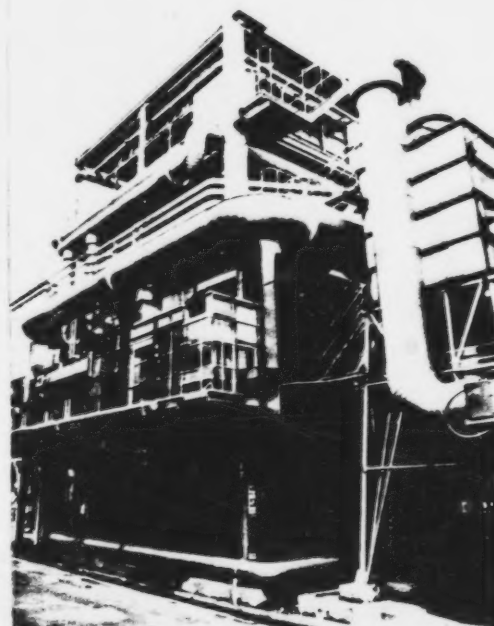


Fig. 10. Tangentially fired pulverized coal furnace at NTI (Coal firing rate 3 ton/hr)

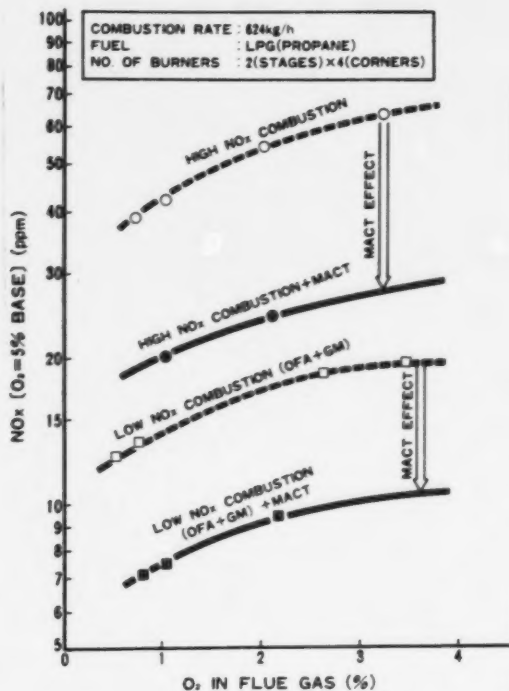


Fig. 11. NOx removal effect for gas firing

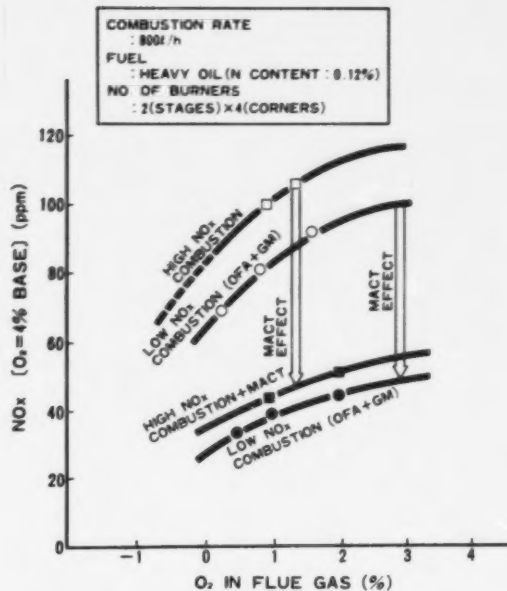


Fig. 12. NOx removal effect for oil firing

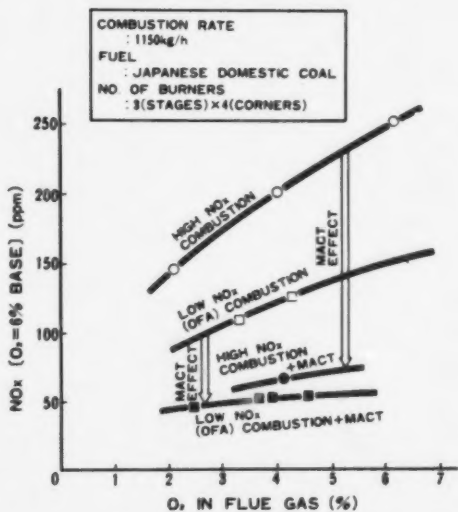


Fig. 13. NOx removal effect for coal firing

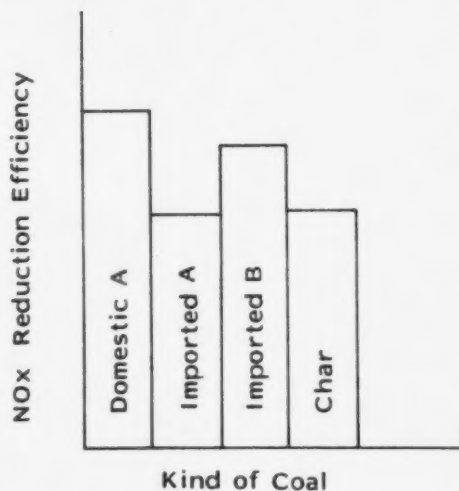


Fig. 14. Relative value of NOx reduction efficiency

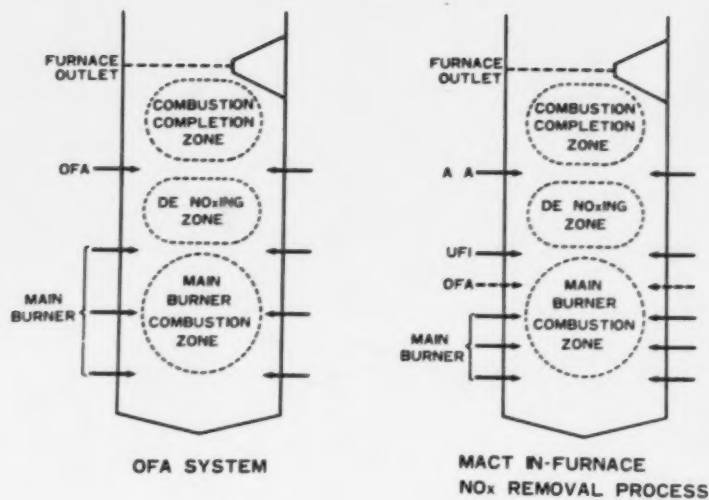


Fig. 15. Comparison of MACT in-furnace NOx removal process with conventional OFA method

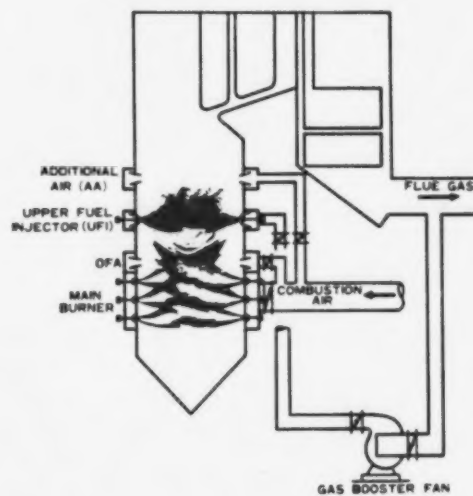


Fig. 16. Schematic diagram of MACT for steam generator

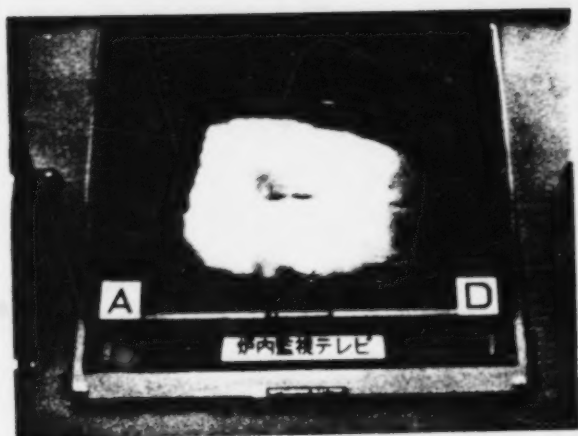


Fig. 17. Furnace TV showing non-MACT operation

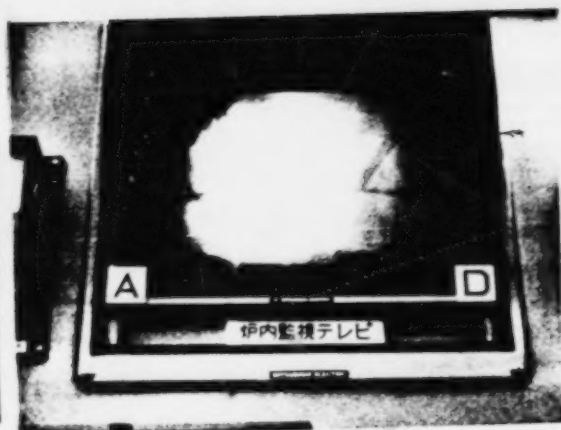


Fig. 18. Furnace TV showing MACT operation

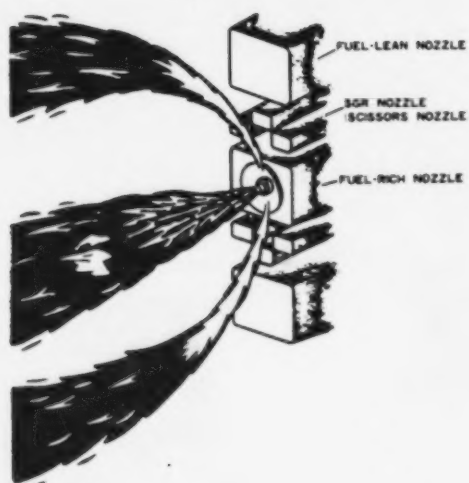


Fig. 19. Nozzle configuration for single-gun type PM burner

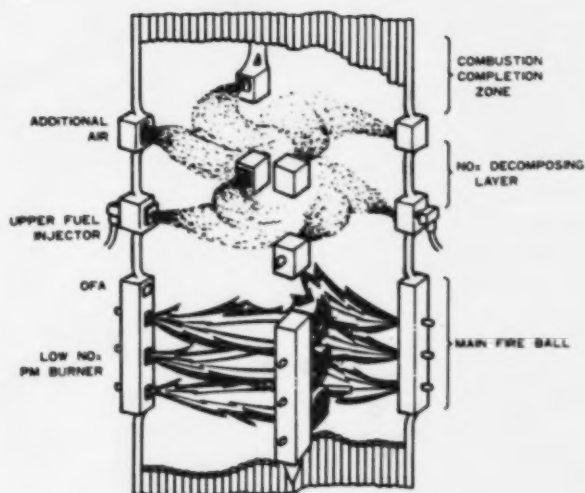


Fig. 20. Bird's-eye view of MACT

Low Sulfur Crude Oil						
HHV(kcal/kg)	γ (15/4)	C	H	O	N	S
10,810	0.851	85.6	13.4	0.8	0.12	0.09

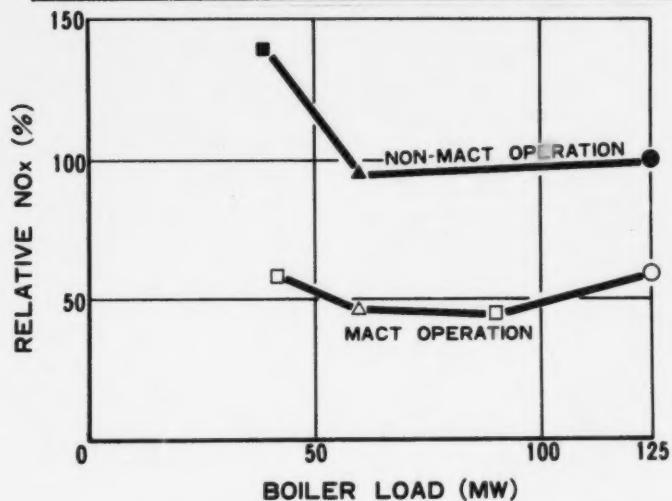


Fig. 21. NOx vs. boiler load

Bunker - C Oil						
HHV(kcal/kg)	γ (15/4)	C	H	O	N	S
10,330	0.954	85.7	11.4	0.2	0.16	2.6

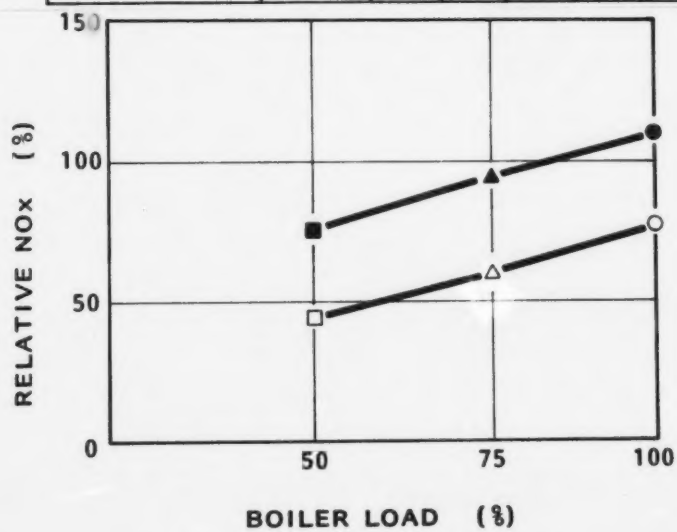


Fig. 22. NOx vs. boiler load

TABLE 1. SPECIFICATION OF CYLINDRICAL FURNACE

Item	Specification	
Furnace	Diameter 0.8 m × Length 2.2 m Castable refractories lined cylindrical furnace	
Cylindrical reactor	Diameter 0.7 m × Length 4 m Diameter 0.5 m × Length 4 m Diameter 0.3 m × Length 5 m	
Primary burner	Combustion rate	Propane 100 kg/h Pulverized coal 100 kg/h
	Air temperature	Ambient temperature
	Pulverized coal carrying gas	Air
Secondary burner	Combustion rate	Propane 100 kg/h Pulverized coal 100 kg/h
	Air temperature	Ambient temperature
	Pulverized coal carrying gas	N ₂ gas

TABLE 2. SPECIFICATION OF TANGENTIALLY-FIRED PULVERIZED COAL FURNACE

Item	Specification
Furnace	Furnace proper : Water-cooled double-wall construction lined with refractory Burner : 3 (stages) × 8 (corners) = 24 (units) Tangentially fired Maximum rate of combustion : 2 × 10 ⁷ kcal/h (Twin furnace)
Fan	FDF Capacity : 920 m ³ /min × 800 mm Aq at 20°C IDF Capacity : 1140 m ³ /min × 800 mm Aq at 100°C GMF Capacity : 760 m ³ /min × 600 mm Aq at 350°C
Air preheater	Regenerative (Ljungström) air heater Capacity : 750 Nm ³ /min × 350°C
Pulverized coal feeding system	(1) Coal rate 2300 kg/h (ground by Bowl Mill) Primary air 8000 m ³ /h × 600 mm Aq (2) Table feeder 4500 kg/h (for main burner) (3) Table feeder 300 kg/h (for UFI)
Dust collector	(1) Cyclone separator 1000 Nm ³ /min × 500°C (2) Bag filter 1200 Nm ³ /min × 120°C

TABLE 3. COAL ANALYSIS

Kind of Coal	Proximate Analysis				Ultimate Analysis (Dry)						HHV ($\frac{\text{kcal}}{\text{kg}}$)
	IM	FC	VM	ASH	C	H	O	N	S	ASH	
Domestic A	6.5	40.8	42.6	10.1	66.5	5.5	16.1	1.09	0.2	10.8	6,400
Imported A	3.0	63.5	19.2	14.3	73.0	4.1	6.9	1.03	0.28	14.7	6,840
Imported B	3.8	60.9	26.0	9.3	74.1	4.1	10.7	0.85	0.69	9.6	6,900
Char	2.9	56.4	5.7	35.0	-	-	-	0.68	-	-	-

NO_x REDUCTION BY REBURNING WITH GAS AND COAL
- BENCH SCALE STUDIES

By:

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"Although the research described in this article has been funded wholly or in part by the United States Environmental Protection Agency through contract number 68-02-3633 to Energy and Environmental Research Corporation, it has not been subjected to the Agency's required peer and policy review and therefore does not necessarily reflect the views of the Agency and no official endorsement should be inferred."

ABSTRACT

Data is presented from a series of bench scale experiments in both gas and coal fired reactors to investigate the effectiveness of the reburning process for NO_x control. The results indicate that a reduction of 50 percent is possible using both gas and coal as the reburning fuel in agreement with Japanese studies. However, for reburning fuels containing high levels of fuel nitrogen, excessive quantities of reburning fuel can cause an increase rather than a decrease in emissions. Coal properties also affect carbon burnout under reburning conditions. Further investigations are required to establish the impact of mixing rates and coal types on the reburning process and to determine the times and temperatures which must be achieved in practice for optimum NO reduction.

INTRODUCTION

Since it was first recognized that nitrogen oxides (NO_x) emitted by stationary sources made a significant contribution to the degradation of air quality, there have been considerable advances in control technology to reduce emissions. NO_x control technologies fall into two categories: those which prevent the formation of nitric oxide (NO) and those which remove NO from the products of combustion. Nitric oxide is formed during combustion either from molecular nitrogen or from nitrogen contained in the fuel. Modification of the combustion process to reduce peak temperatures and maximize residence times under fuel rich conditions minimize NO formation from both of these sources. Consequently, provided the process requirements are satisfied combustion modification provides a cost effective method of controlling NO_x emissions. However, when the process is not tolerant to combustion modification or very low emission levels are required it may be necessary to use flue gas cleaning techniques to remove NO_x from the combustion products. This paper addresses a technology which removes NO from combustion products using fuel as the reducing agent and involves similar kinetic processes to

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those involved in combustion modification techniques. This technology is variously referred to as:

- in-furnace NO_x reduction;
- reburning;
- staged fuel injection.

Reburning can be considered as the process which allows "in-furnace NO_x reduction" to take place.

The basic concepts associated with in-furnace NO_x reduction by reburning are not new. The reduction of NO by flames has been appreciated for over a decade. A flue gas NO_x incinerator was developed by the John Zinc Company (1). The term "reburning" was coined by Wendt, Sternling and Matovich (2) who reduced NO produced in a laboratory scale flat flame by adding methane or ammonia to the combustion products. Recently, Japanese investigators have reported the application of reburning to large test furnaces and there are field demonstrations of the technology currently in progress (3). The MACT (Mitsubishi Advanced Combustion Technology) in-furnace NO_x removal process applies the concept of reburning to a boiler. Part of the fuel bypasses the main heat release zone and is injected above the main burners to provide the fuel for reburning. It is claimed that the NO_x produced by the main firing system can be reduced "to half at any level of concentration." In an in-furnace de- NO_x combustion test using a low NO_x gas burner, NO_x emissions as low as 8 ppm (calculated at 5 percent oxygen) have been reported. Takahashi et al (3) indicate that irrespective of the fuel used for reburning the NO_x level produced by the main combustion system is reduced by never less than 50 percent.

Reburning is a process whereby NO produced in the main heat release zone is reduced downstream by fuel addition. This downstream reduction process can take place in a flame with extensive thermal and concentration gradients or zones with almost uniform conditions. In this study, bench scale reactors were used to generate the latter conditions and thus the process was divided into two zones:

- NO Reduction Zone. The reburning fuel is added to the combustion products of the main combustion zone which operates fuel lean. NO is reduced by hydrocarbon radicals producing nitrogenous intermediates such as NH_3 , HCN as well as molecular nitrogen. Consequently, the NO in the exhaust from the main combustion zone is converted either to N_2 , NH_3 , HCN, or retained as NO. When the reburning fuel contains nitrogen (e.g., if the reburning fuel is coal) the coal nitrogen could remain with the char or form NO, HCN, and NH_3 . Thus the products of this first process contain nitrogen species which can be converted to NO, namely char nitrogen, NH_3 and HCN as well as NO, which will be referred to as total fixed nitrogen (TFN).

- TFN Oxidation Zone. Here air is added to ensure burnout of the reburning fuel. The NH_3 , HCN , NO , and char nitrogen are either converted to N_2 or NO .

Consequently, the formation of N_2 can occur in both zones, thus reducing emissions. However, it is also possible to form NO in the TFN oxidation zone due to the additional nitrogen accompanying the reburning fuel, thereby increasing emissions.

Explained in this way, reburning appears to have many of the same features as staged combustion - a fuel rich zone followed by a burnout zone. There have been extensive studies to establish the fate of molecular and fuel nitrogen under these conditions. Consequently, the kinetic mechanisms involved in the reburning process are reasonably well understood. The limits imposed by thermodynamics on NO formation under fuel rich conditions are much lower than those achieved in practice. Figure 1a is a plot of equilibrium levels of total fixed nitrogen species (HCN , NH_3 , and NO) as a function of stoichiometry and temperature. Except for high temperatures (greater than 2000 K) and rich conditions ($\text{SR} < .5$), the equilibrium levels are less than 10 ppm. However, under lean conditions, equilibrium NO levels can be significant, even for moderate temperatures. Equilibrium considerations would dictate operation of a combustor at moderate temperatures under rich conditions or low temperatures near stoichiometric conditions.

In reality, the kinetics which dictate the speed at which the concentration levels approach equilibrium, are slow. Therefore, despite the fact that equilibrium levels are low, the actual emission levels are much higher due to finite reaction rates and times. There are two ways that the reaction rates can be increased: increasing temperature and increasing the levels of reactive free radicals. Traditional staged combustion takes advantage of both of these by burning the fuel nitrogen species at high temperatures in a rich flame where free radical concentrations are high. Reburning takes advantage of the latter option by increasing the level of free radicals without significant modification to the temperature. Figure 1b presents a schematic of the overall gas-phase reactions occurring during reburning. The hydrocarbon fuel reacts with oxygen to form hydrocarbon fragments such as CH , CH_2 , and CH_3 which subsequently react with NO to form cyanide species. These cyanide species are coupled with the amine subset principally through NH . The amine species can then react in several ways depending on conditions. NH will react with OH , H , and O_2 to form either HNO or N at about equal rates. HNO breaks down relatively fast into NO ; however, atomic nitrogen can either form NO (predominantly) or N_2 . A secondary reduction path through NH involves the formation of the intermediate N_2O which is relatively unstable at high temperatures and rapidly decomposes to N_2 .

It was the intent of the studies described in this paper to examine the parameters controlling the effectiveness of reburning by conducting a series of bench scale reactor studies with well defined conditions in the NO reduction and the TFN oxidation zones.

EXPERIMENTAL STUDIES

Two series of bench scale studies were carried out; one using gaseous fuels to isolate gas phase mechanisms and the other using pulverized coal as the reburning fuel. The gas phase experiments were carried out in the back-fired reactor shown in Figure 2a. A 5.7 cm I.D. alumina muffle tube separated the reaction zone from the propane/oxygen-enriched-air backfired zone. The reaction zone was divided into primary, NO reduction, and TFN oxidation stages to simulate in-furnace NO_x reduction. Premixed primary reactants were introduced at the top of the reactor through a water-cooled, stainless steel burner. Reburning fuel was injected radially outward at a position 2.3 cm downstream from the burner using a 1.27 cm O.D. quartz injector tube situated on the centerline of the reactor. Air was injected in a similar fashion 38 cm further downstream to combust the products from the NO reduction zone. Samples were withdrawn through a water-cooled, stainless steel probe situated 17.8 cm downstream of the injector.

The reburning investigations with pulverized coal were conducted at 20.5 kW in the refractory lined tunnel furnace shown in Figure 2b. This reactor has five separate sections with an internal diameter of 15.2 cm, and is 1.2 m long. The reburning fuels (primarily pulverized coal) were injected downstream of a radiation shield. The reburning fuels included propane, a lignite from Beulah, N.D., a high volatile bituminous coal from Utah, some work with a medium volatile coal from Rosa, Alabama, and a predried Australian brown coal from Morwell (see Table 1 for properties). A staging choke separated the NO reduction zone from the burnout zone. Air to complete the combustion was supplied radially through an injection ring. Exhaust gas samples were withdrawn with a stainless steel, water-jacketed probe and analyzed using standard continuous instrumentation. A water spray probe was used for extracting in-flame samples which were analyzed with specific ion electrodes for nitrogen intermediates.

Reactant Stoichiometry

The required stoichiometry for optimization of the NO reduction zone is an important parameter because it establishes the amount of fuel which must be added to this zone (reburning fuel) and it controls the composition of the reactants entering the TFN oxidation zone. Figure 3a shows the effect of NO reduction zone stoichiometry (SR_2) on the percentage NO reduction in the back-fired reactor when the gaseous reburning fuel both contained and was free of bound nitrogen (the CH_4 was doped with NH_3). At the optimum stoichiometry (around 90 percent theoretical air) approximately half of the NO was removed by reburning regardless of the secondary fuel nitrogen content. The percentage NO reduction at richer NO reduction zone stoichiometries increased more rapidly when fuel nitrogen was present in the reburning fuel due to the increased ratio of reburning to primary fuel, suggesting that the nitrogen content of the reburning fuel may be of major importance if the reburning system is not fully optimized. Figure 3b shows the fixed nitrogen (XN) levels at the exit of the NO reduction zone as a percentage of the initial NO under the same conditions. The open data points and solid lines indicate the data obtained with the nitrogen-free reburning fuel; the shaded points and dotted

lines indicate the presence of 0.5 percent ammonia in the reburning fuel. In general, the NO levels at the exit of the NO reduction zone do not appear to be greatly influenced by the presence of the fuel nitrogen. In both cases the NO decreased sharply as SR_2 decreased. These data suggest that the presence of nitrogen in the reburning fuel does not greatly retard the destruction of primary NO. However, as the stoichiometry is further reduced, this decrease in NO is offset by a corresponding increase in HCN, the dominant fixed nitrogen species at low values of SR_2 . HCN levels at the exit of the NO reduction zone were approximately 50 percent higher when fuel nitrogen was included with the reburning fuel. These tests were carried out with a relatively high concentration of NO at the exit of the main heat release zone (500 ppm). Under these conditions it is reasonable that the nitrogen content of the reburning fuel does not affect exhaust NO values.

The influence of NO reduction zone stoichiometry on the effectiveness of reburning using coal as the reburning fuel is summarized by the data presented in Figure 4. As SR_2 decreases with the addition of reburning fuel, the exhaust NO is reduced dramatically until at the optimum stoichiometry ($SR_2 \approx 0.9$) a fifty percent reduction is obtained. Further decreases in SR_2 cause an increase in the exhaust NO (see Figure 4a). Figure 4b shows the results of gas phase concentration measurements made at the exit of the NO reduction zone. The purpose of the NO reduction zone is to react the nitric oxide leaving the main heat release zone with hydrocarbon radicals provided by the reburning fuel by reactions such as:



and



Figure 4b indicates that, as expected, this type of reduction is occurring at all rich zone stoichiometries. In addition, there appears to be considerable interconversion of nitrogen among different fixed nitrogen species. At SR_2 less than 0.8, NH_3 and HCN formation becomes significant. Further, these data demonstrate that as the secondary zone stoichiometry is reduced, the summation of the XN species increases dramatically. Figure 4c summarizes the fate of the available nitrogen on a cumulative basis and includes consideration of the char nitrogen. These results emphasize that at low secondary zone stoichiometries, char nitrogen carry-over (into the TFN oxidation zone) can be extremely significant. When the SR_2 is decreased from 0.9 to 0.7 the amount of reburning fuel nitrogen input to the system approximately doubles, yet the char nitrogen carry-over increases from the equivalent of approximately 40 percent of the initial NO level to almost 150 percent of the initial NO level. Additionally, the fraction of the available reactive nitrogen which is converted to N_2 decreases significantly as SR_2 is decreased.

Thermal Environment

Experiments were conducted to assess the influence of the thermal environment of both the NO reduction and the TFN oxidation zones on the reburning process. It is well established that thermal history can have a significant influence on the fate of nitrogen species under fuel rich and staged combustion conditions. England et al (4) have shown that in liquid fuel fired systems, it is desirable to have a nearly adiabatic fuel rich

first stage to promote the evolution of the nitrogen from the liquid phase and maximize the rate of the XN species decay toward their low equilibrium levels prior to the addition of the second stage air. However, Johnson et al (5) found that with pulverized coal, significant heat removal was beneficial with respect to overall NO_x emissions. Chen et al (6) found similar results for pulverized coal and defined the overall mechanisms by investigating the component processes. These results indicate that decreasing the primary zone temperature tends to decrease exhaust NO_x level because, although the rate of TFN decay in the rich zone is decreased and the amount of char nitrogen carried into the excess air region increases, these effects are more than compensated by a marked decrease in the conversion of gas phase TFN species to NO in the final excess air flame. In particular, these investigators have postulated that increased heat extraction reduces exhaust NO_x emissions because of selective reduction of NO by NH_1 species in the final zone. When this affect occurs, the composition and thermal conditions are similar to those defined by Lyon (7) for external "de- NO_x ."

In a previous study Chen et al (6) have further shown that the effectiveness of increased heat extraction depends heavily on the composition of the coal being burned. With low rank coals, increasing the heat removal only reduced exhaust NO_x emissions at high stoichiometries. Increased cooling had little effect on the TFN concentrations; however, at very rich conditions, it increased the carry-over of solid nitrogen. Thus, in these cases the decreased emissions associated with reduced gas phase conversions were mitigated by increased contributions from char nitrogen. Alternatively, with some high volatile bituminous coals, reducing rich first stage temperature actually had no effect on the overall exhaust NO emissions. Detailed internal measurements indicated that this was because the decreased TFN conversion was completely compensated by significant increases in the first stage NO emissions. This effect was particularly prominent with high rank bituminous coals which produced little NH_3 .

Figure 5 shows experimental data on the influence of overall temperature on the effectiveness of reburning with gaseous fuels. These results were obtained with the backfired bench scale reactor using methane as the reburning fuel. The data shown in Figure 5 indicate that increasing the temperature significantly increases the amount of NO reduction with the addition of reburning fuel (due to an increased rate of N_2 formation). However, the increased temperature also increases the conversion of the XN species to NO and, hence, for these conditions the exhaust NO level is independent of the thermal environment. This can be contrasted with the data presented in Figure 6 which illustrates that the addition of cooling coils to the NO reduction zone dramatically reduced exhaust NO levels for two initial NO concentrations (633 and 148 ppm) using low rank coal as the reburning fuel.

Detailed XN species measurements were made at the exit of the NO reduction zone in an attempt to explain the results presented in Figure 6. Cooling had relatively little effect on the concentrations of HCN and NH_3 leaving the zone (except at the extremely low stoichiometries); however, decreasing the temperature significantly decreased the rate of NO decay within the NO reduction zone and resulted in a much larger char nitrogen carry-through. These results are essentially identical to those measured

previously by Chen et al (6) for normal staged combustion systems. Decreasing the temperature of the rich zone tends to retard both the formation of N_2 from the gas phase TFN species and the evolution of nitrogen from the solid phase. Figure 7 shows the overall TFN (including char nitrogen) for both the normal and cooled case. The significant increase in TFN with cooling is the direct result of the higher NO and char nitrogen concentrations. Figure 7 also shows the overall conversion of the TFN at the exit of the NO reduction zone to exhaust NO. Heat extraction in the NO reduction zone reduces exhaust emissions (Figure 6) because the conversion of the reactive nitrogen to NO in the TFN oxidation zone decreases greatly in the cooled case. The dramatic decrease in the TFN conversion at reduced temperatures is believed to be associated with selective NO reduction by NH_4 species as proposed by Lyon (7). Gas phase temperatures measured at the exit of each zone indicates that in the cooled case the reactants entered the TFN third oxidation zone at approximately $800^{\circ}C$. Thus, in this case the local flame temperatures in the oxidation zone were in the ideal region ($800 - 1000^{\circ}C$) for selective NH_4 reduction.

Reburning Fuel Composition

The properties of the reburning fuel can influence the reburning process directly and also affect its application in practical systems. Figure 8 shows the results from a series of carefully controlled tests where the fuel nitrogen content of the reburning fuel was varied from 0 to 1.67 weight percent nitrogen as NH_3 . In all of these experiments the primary zone fuel was also propane and the initial NO was 633 ppm. These data indicate that, as previously reported, the optimum NO reduction zone stoichiometry is approximately 0.9 and that further decreases ultimately result in decreased reburning efficiency. These data also show that under optimum reburning conditions, fuel nitrogen content has a relatively minor impact on reburning efficiency. However, if too much reburning fuel is added exhaust values increase considerably.

Data presented earlier in Figure 4a illustrate both the similarities and differences between gaseous and solid fuels for reburning. Figure 9 compares data obtained with the Beulah coal and propane plus ammonia (both as the reburning fuel) with matched nitrogen contents as a function of the initial NO concentration. These results show that at the optimum stoichiometry condition the propane-ammonia simulates the Beulah coal performance quite well. The data strongly suggest that heterogeneous effects are of second order importance. However, experiments conducted with three reburning fuels at both normal and heavily cooled conditions indicate that with both propane and propane/ NH_3 as the reburning fuel, the thermal environment has essentially no effect on the effectiveness of reburning, particularly the TFN oxidation step. However, in the case of the Beulah coal, a large increase in reburning effectiveness was achieved when the temperature of the TFN oxidation zone was reduced. This latter observation suggests that heterogeneous effects can be significant in the reburning process and they may be dependent upon temperature, solid composition, gas phases, species, etc.

Figure 10 shows the results where a variety of coals were used as the reburning fuel. Throughout these tests the rich zone stoichiometry (SR_2) was 0.9 (optimum) and the furnace was uncooled. These data indicate that as the nitrogen content of the reburning fuel increased, the effectiveness of the reburning only decreased slightly when the initial NO level was high. However, when the primary NO level was reduced to 148 ppm, the nitrogen content of the reburning fuel became more important. In addition, the Rosa coal results indicate that reburning certain coals can be difficult because with this medium volatile bituminous coal almost 10 percent of the reburning fuel was unburned (emitted as carbon particulate) even at the optimum reburning conditions.

SUMMARY

Figure 11 presents a comparison between the data obtained in this study, that reported by other investigators for bench scale experiments, and a prediction using the FCR fuel nitrogen kinetic mechanism. It can be seen that all the data are in reasonable agreement:

- reburning can reduce NO by at least fifty percent;
- maximum reductions occur with a NO reduction zone stoichiometry of about 0.9;
- significant reductions can occur with the addition of smaller amounts of reburning fuel and an overall fuel rich zone is not necessary if reductions of less than 50 percent can be tolerated.

However, these experiments were conducted under ideal conditions which are not necessarily representative of practical operations. The constraints imposed by field practice (finite rate mixing, real fuels, burnout, heat transfer, etc.) will be the subject of a further EPA study sponsored by the CRB (Project Officer Robert Hall). The influence of jet mixing rates can be extremely important because of their impact on local conditions, overall reactant contacting, and reburning fuel requirements.

ACKNOWLEDGMENTS

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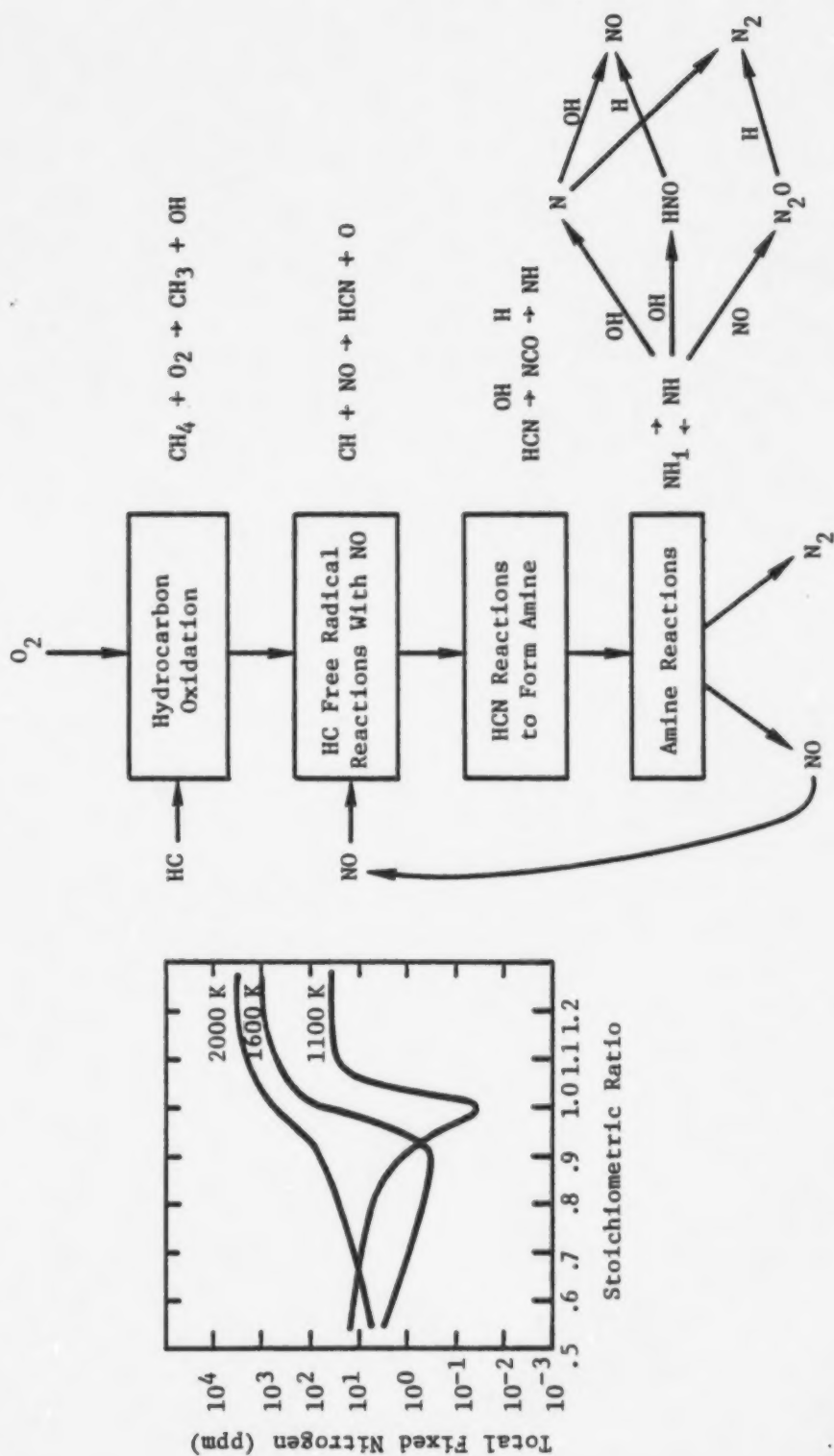
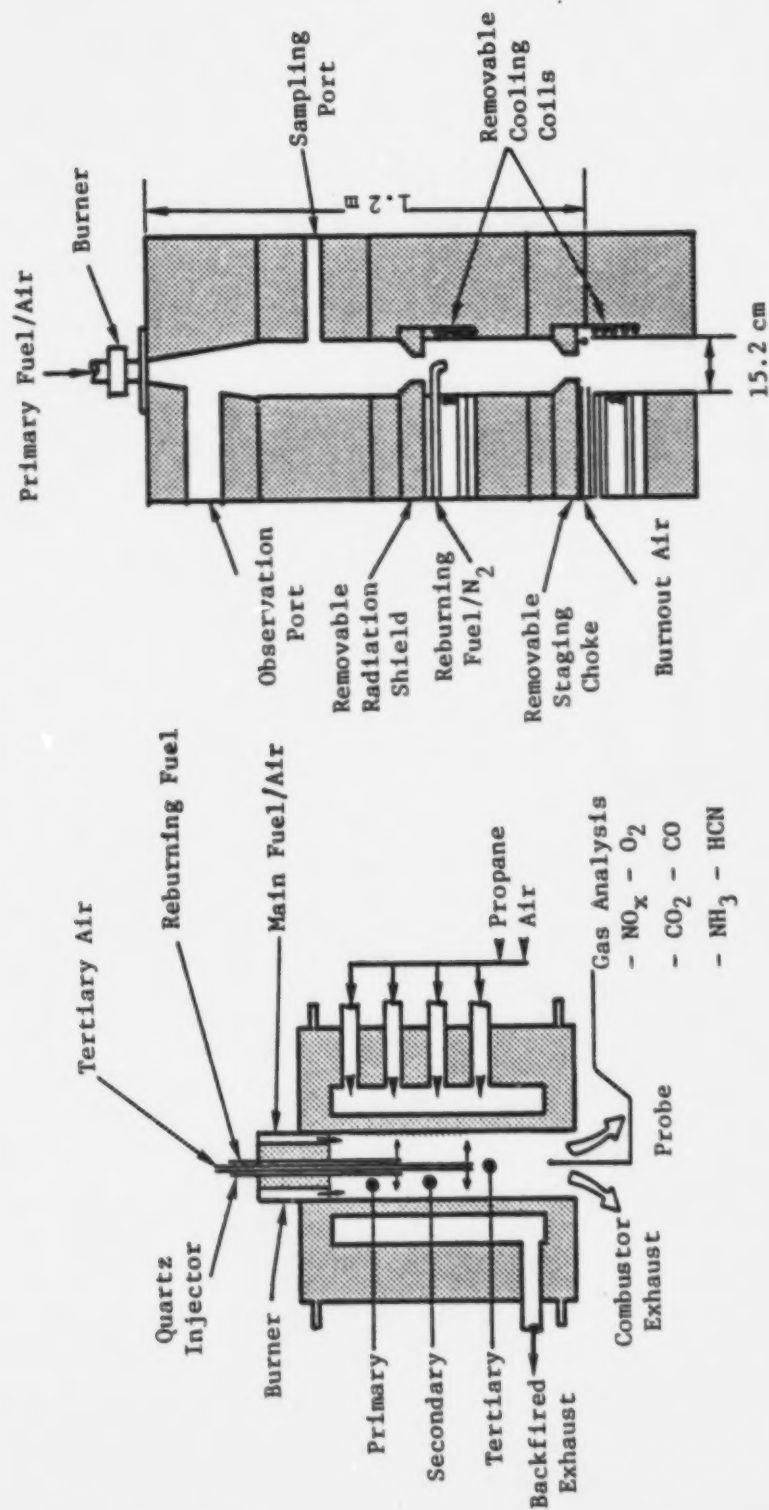


Figure 1. Gas phase reactions and reburning.



a) Back heat gas reactor. b) Coal fired reactor system.

Figure 2. Bench scale reactor systems.

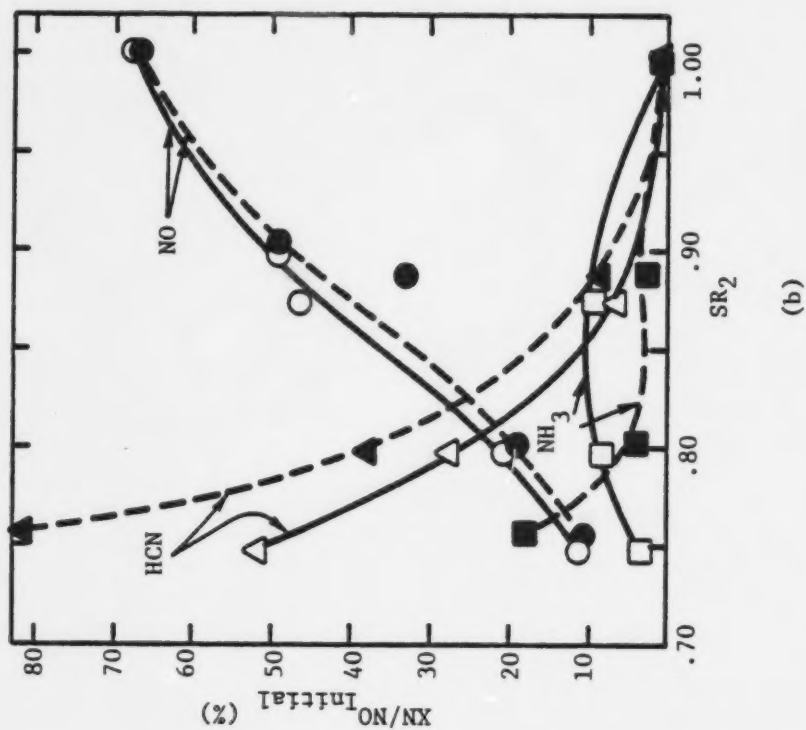
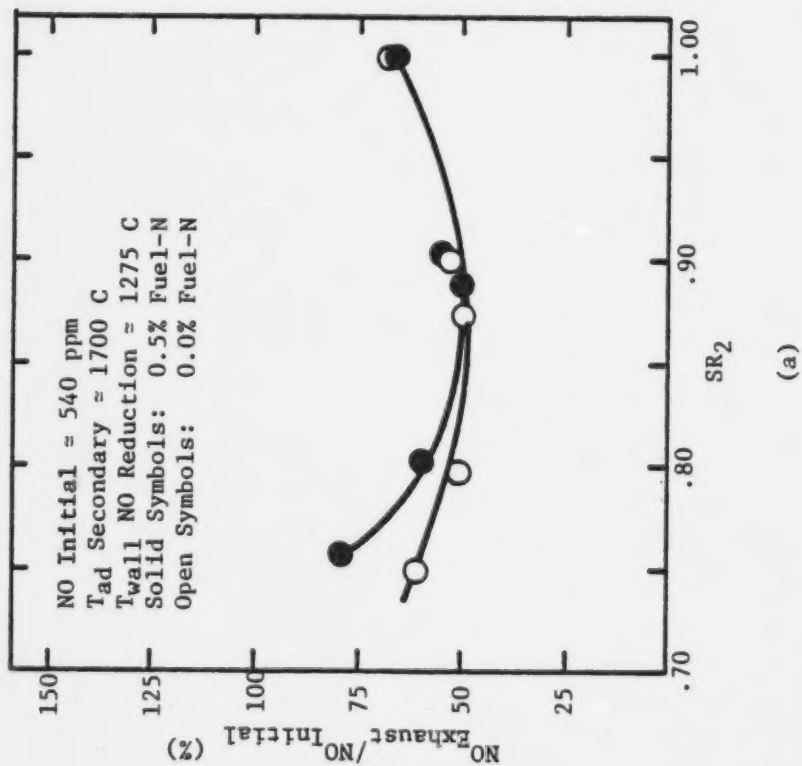


Figure 3. The effect of NO reduction zone stoichiometry (gas fired reactor, CH₄ reburning fuel).

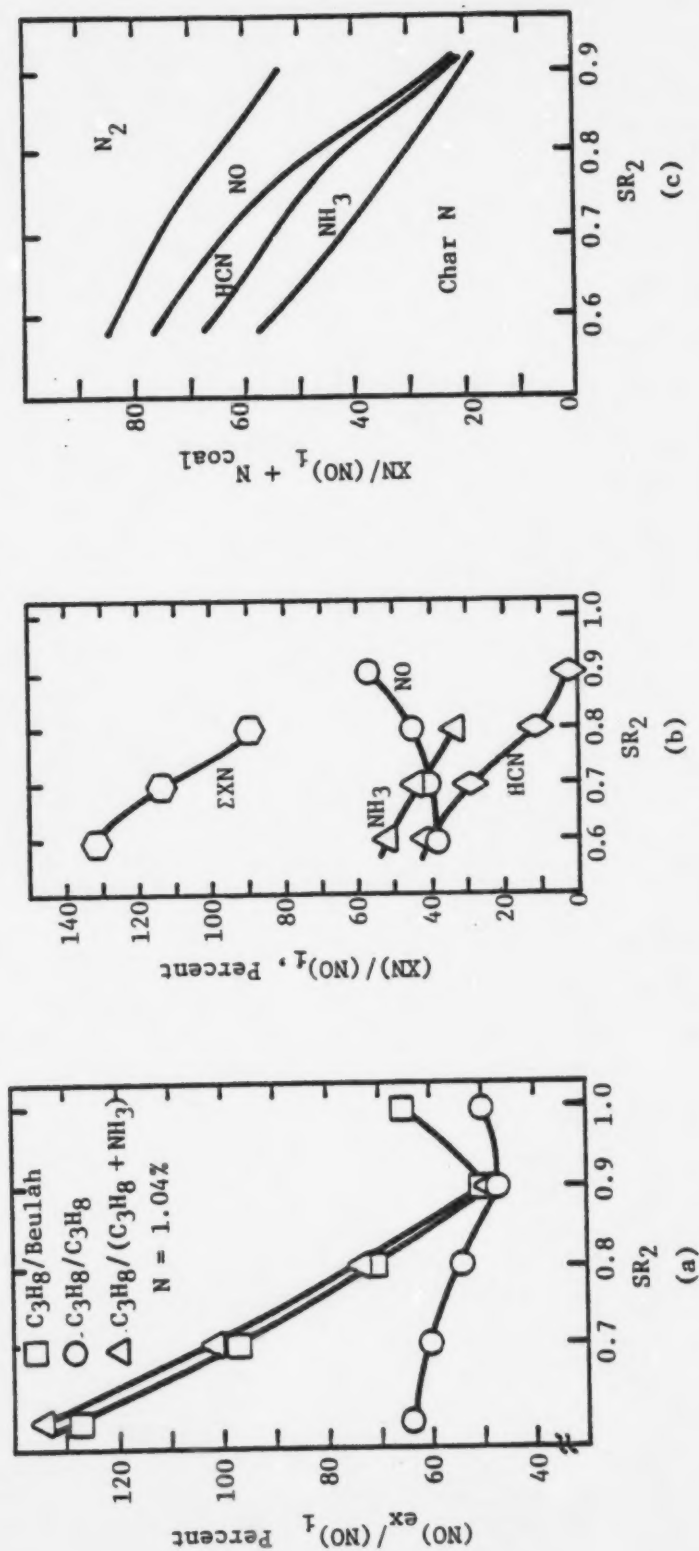


Figure 4. The effect of NO reduction zone stoichiometry (coal fired reactor; $NO_{initial}$ 633 ppm, $SR_1 = 1.1$, $SR_3 = 1.25$, main heat release zone propane, reburning fuel Beulah coal).

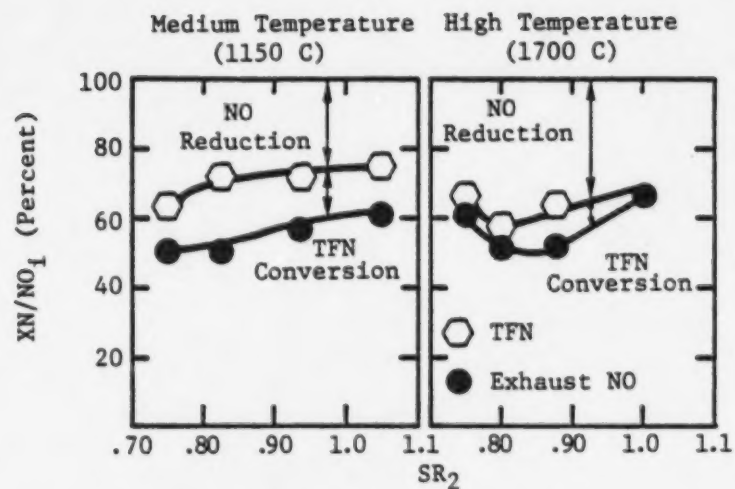


Figure 5. NO reduction and TFN conversion at two temperatures (CH_4/N_2 as the reburning fuel).

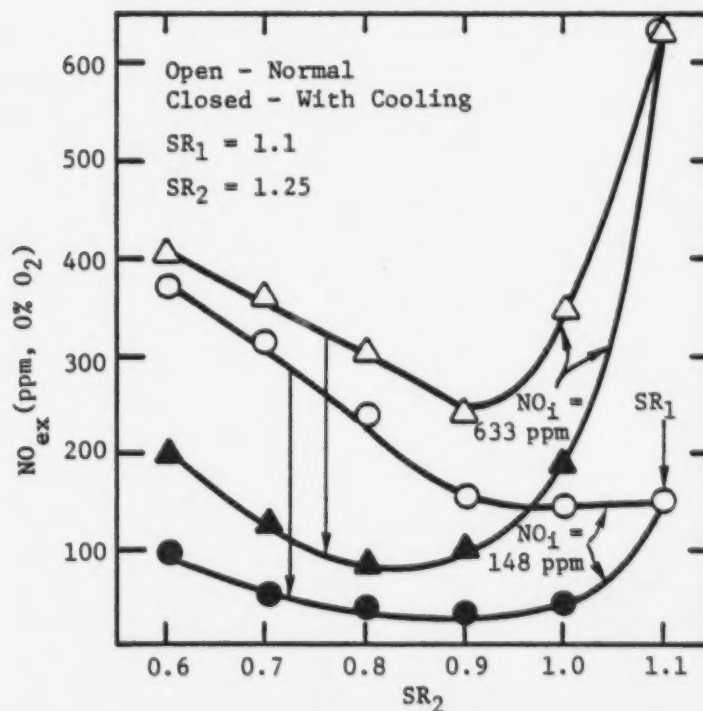


Figure 6. The effect of NO reduction zone cooling on exhaust NO emissions (C_3H_8 doped/Beulah).

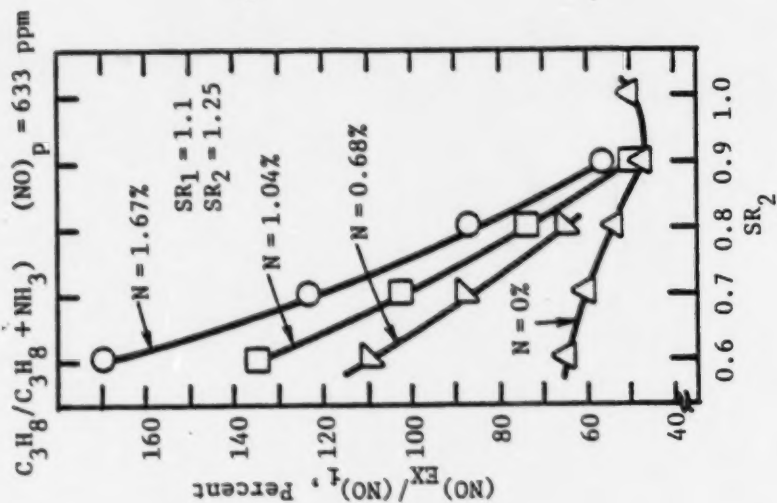


Figure 8. Effect of SR_2 and reburning - fuel nitrogen content (tunnel furnace).

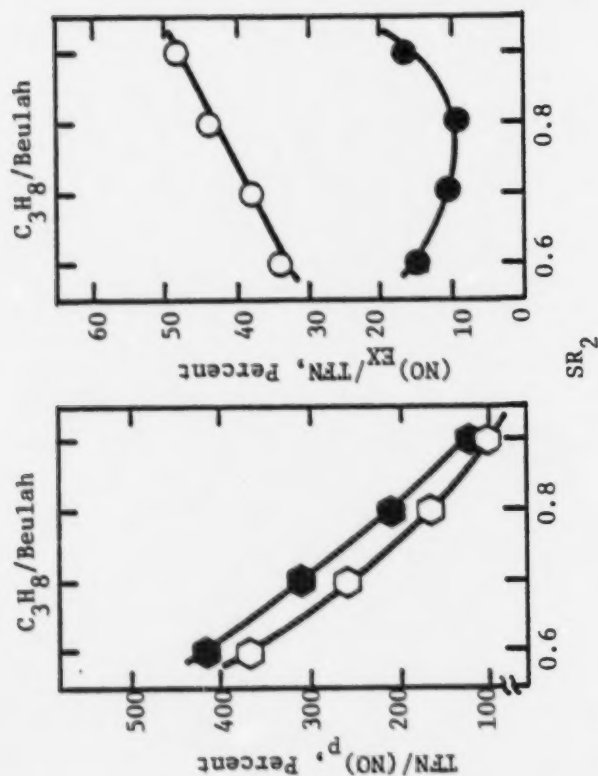


Figure 7. NO reduction zone cooling: Effect on TXN formation and conversion.

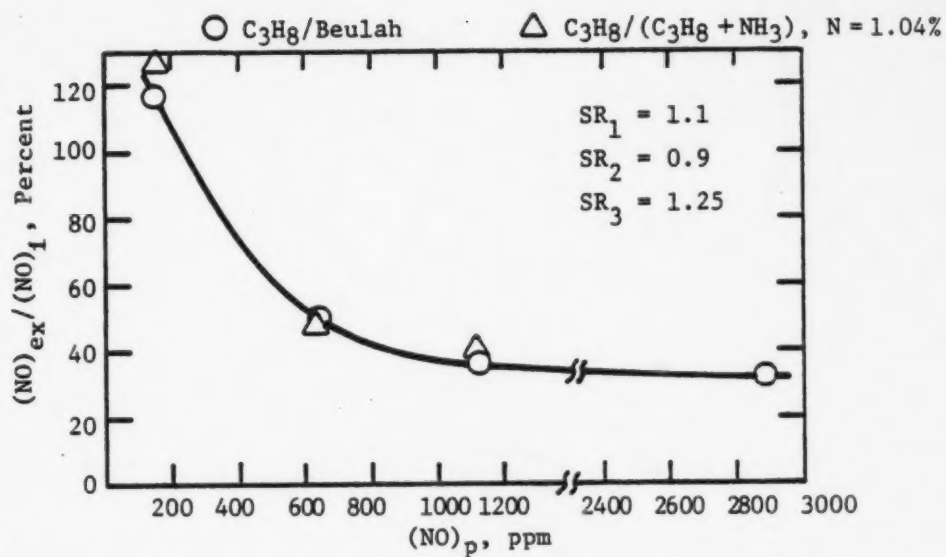


Figure 9. Influence of reburning fuel type and primary NO level (tunnel furnace).

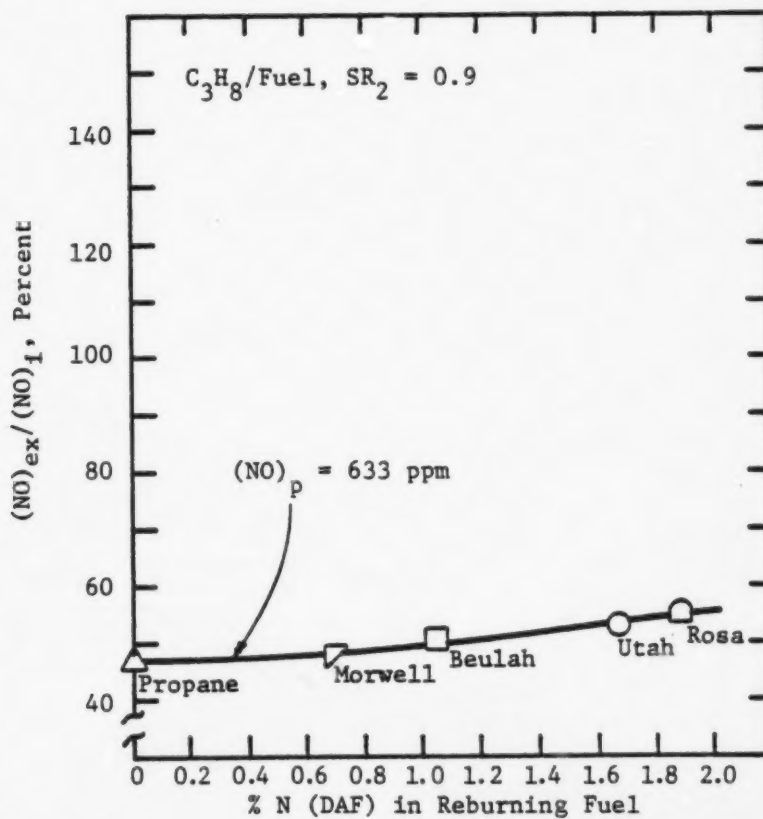


Figure 10. Impact of nitrogen in reburning fuel on NO_x reduction.

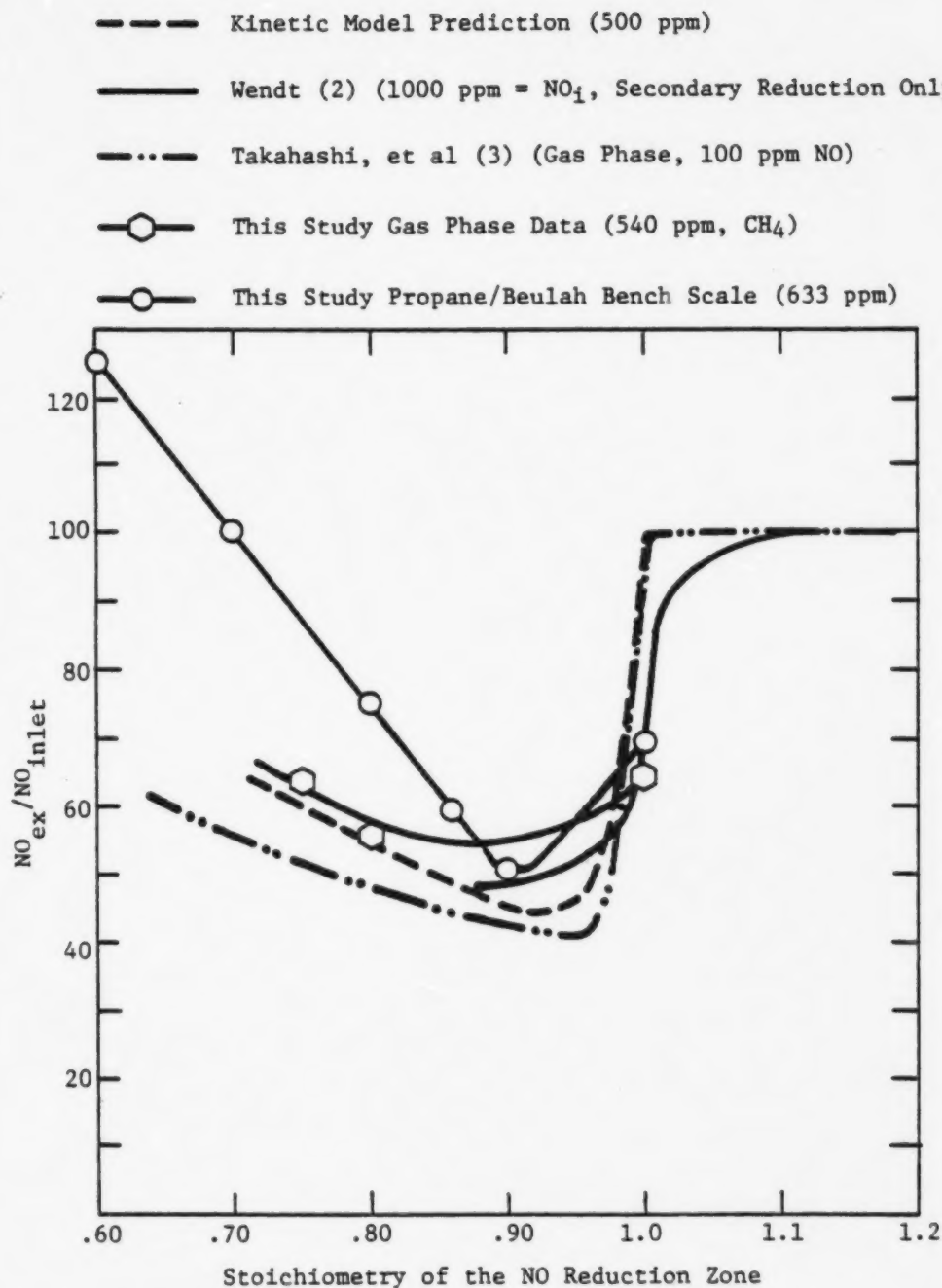


Figure 11. Effectiveness of reburning - comparison of bench scale studies.

TABLE 1. COAL PROPERTIES

	UTAH	BEULAH	MORWELL	ROSA
Proximate Analysis (As Received)				
Moisture	6.39	34.63	9.07	8.02
Ash	7.40	4.97	3.38	6.79
Volatile Matter	47.32	27.02	48.79	21.81
Fixed Carbon	47.32	33.38	38.76	63.38
Ultimate Analysis (% Dry)				
Carbon	73.17	66.15	66.25	81.23
Hydrogen	5.55	4.20	5.01	4.73
Nitrogen	1.54	.96	0.65	1.74
Sulfur	.66	.37	0.28	1.04
Ash	7.90	7.60	3.72	7.38
Oxygen	11.18	20.72	24.09	3.88
Rank	HVB Bituminous	Lignite A	Predried Australian Brown Coal	MV Bituminous

FUEL STAGING FOR PULVERIZED COAL FURNACE NO_x CONTROL

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ABSTRACT

A 16.1-kW idealized subscale combustor was used to define the NO_x emission control benefits of fuel staging. NO_x control is achieved by injecting coal, as well as combustion air, at two locations in the combustor. The NO_x and combustion product gases from the first-stage flame are mixed with fuel and air in the second stage and reburned. The fuel fragments, fuel nitrogen components, soot and char produced by the reburning interact with the previously formed NO_x, reducing it to low levels within a fraction of a second. This combustion modification approach has lowered NO_x by over 70 percent from baseline levels. Current test results show that second-stage stoichiometry is a dominant process variable, and that effective NO_x reduction requires that the second stage be operated fuel rich. First- and third-stage stoichiometries and fuel fraction injected into the second stage were less important to the process, as long as the second stage was operated under fuel-rich conditions.

Based on the test results of this study, process variable regimes were identified where fuel staging has a distinct advantage in controlling NO_x emissions over classical staging. These are cases where the first stage is operated fuel lean and the second stage is operated fuel rich.

INTRODUCTION

A constraint in substituting coal for presently used relatively "clean" oil and gas fuels is the increase in gaseous and solid emissions that will accompany their use in existing combustors. In particular, total U.S. NO_x emissions will increase substantially if pulverized coal is substituted for natural gas and distillate oil fuels in existing technology combustors. This is due to the large amounts (~1 percent) of fuel-bound nitrogen contained in the coal relative to the small amounts of nitrogen found in petroleum distillate fuels and the absence of bound nitrogen in natural gas. This nitrogen is partially converted to NO_x when the coal is burned conventionally, resulting in high emissions.

To prevent degradation of the environment by NO_x emissions from burning pulverized coal, the DOE, EPA, and private groups have funded the development of NO_x control techniques, primarily for utility boiler applications. These studies showed that coal combustion NO_x emissions were sensitive to combustion condition modification, and substantial NO_x reductions could be achieved with techniques such as controlled-mixing low- NO_x burners, overfire air (OFA), and reduced volumetric firing rate (reference 1). Additional NO_x reduction can be achieved by passing the products from the initial combustion through a second-stage flame. This "fuel staging" process could provide combustor designers with an additional option to control NO_x in pulverized-coal-fired boilers. This paper describes an experimental study to define the pulverized-coal NO_x emission control benefits of fuel staging.

Several laboratory studies (references 2 and 3) have shown that non-nitrogen-bearing fuels introduced into NO_x -laden combustion products lead to reburning and subsequent NO_x reduction of up to 76 percent. Both flat-flame burners (reference 2) and tubular reactors (reference 3) were used in these studies, and reductions were observed to occur in less than 1 sec. In these studies, the effectiveness of the reduction increased when the oxygen in the combustion gases was depleted by secondary fuel injection. Maximum reduction was observed when the amount of fuel exceeded the available oxygen limit and unburned fuel exited the reactor.

Reduction of NO in diffusion flames, by passage through the flame zone, has also been found (reference 4). In these cases, NO was either injected into the fuel jet or into the combustion air. In passing through the flame zone, either from the rich or lean side, the NO was observed to decrease. The NO reduction from passage through the fuel-rich side, or fuel side, appeared to be higher than from the fuel-lean or air side.

The same types of reductions can be seen in pulverized-coal-fired systems where heterogeneous as well as homogeneous processes are active. NO dopant has been injected into a variety of firebox locations in a pulverized coal, pilot-scale, tangentially fired system (reference 5). In this single-burner-level system, dopant was injected below, at, and above the fuel entry location for both air-staged and unstaged conditions. Up to 94 percent of the NO dopant was reduced. The reduction was most effective in intensively burning rich flame zones and rich postflame zones, and was much less effective in lean postflame zones (reference 5).

Mitsubishi Heavy Industries (MHI), in a joint project with Tokyo Electric Power Company, performed sub- and pilot-scale fuel-staging tests (reference 6). This study was directed at gas-, oil-, and coal-fired utility boiler applications.

In the subscale reactor tests, gas, oil, or coal was added to premixed and electrically heated mixtures of NO, O_2 and N_2 in a downstream section to reduce the NO concentrations. For these fuels, a maximum NO reduction of approximately 90 percent is achieved at stoichiometric ratios between 0.8 and roughly 0.4. For propane fuel, the reduction process appears to be roughly completed by 0.1 sec and is independent of inlet NO concentration from 40 to 1,000 ppm inlet NO. Also, for fuel-rich conditions, NO decomposition appears

to increase with reaction temperature, achieving maximum decomposition at about 1150°C.

Pilot-scale, corner-fired furnace experiments with gas, oil, and coal fuels were also run with both regular and low-NO_x burners. Figure 1 shows how fuel staging was integrated into the pilot-scale furnace. The lower furnace burner arrangement is typical of conventional tangentially fired furnaces. Figure 2 shows the NO reductions observed using the fuel-staging approach compared to the conventional or low-NO_x burner approach. These results show that the fuel-staging process reduces NO by 50 percent or more, roughly independent of the fuel type and initial burner NO production.

Following the Japanese work, Energy and Environmental Research Corporation (EERC) performed some bench-scale experiments (reference 7) with pulverized coal to further investigate the parameters examined in the Japanese work. The inlet gases were generated by a doped propane/air flame. For inlet NO concentrations of 633 ppm or higher, Beulah lignite and Utah coal fuels showed maximum NO reductions from baseline of over 50 percent at stoichiometries of 0.9 and 0.8, respectively.

For the case of 148 ppm initial NO concentration, NO emissions actually increased rather than decreased as the amount of coal in the reduction zone increased. Apparently, coal combustion in the second stage generated significant NO or NO precursors, which offset any reduction of first-stage NO.

This paper describes tests which characterized the fuel-staging process in a well-defined subscale, pulverized-coal-fired combustor. The important parameters of stoichiometry, residence time, and the fraction of fuel burned in the second stage were defined by these experiments. The experimental investigation is continuing along with a data analysis task which will help define the mechanisms and rates of the fuel-staging process.

EXPERIMENTAL EQUIPMENT

In the fuel-staging combustor used in this study and shown in figure 3, fuel and air are premixed and injected into the top of the combustor where they burn in a planar mode in section 1 of the combustor. The combustor is a cylindrical chamber 20.3 cm (8 in.) in internal diameter, 91.4 cm (36 in.) in external diameter and 182.9 cm (72 in.) long. Multiple 4.5 cm (1-3/4 in.) diameter ports, labeled A through Q in figure 3, are provided along the combustor length. At station "a" the remainder of the fuel is injected with additional air and rapidly mixed with the combustion products from section 1. The NO_x reduction process occurs in section 2. Finally, air needed to complete combustion is injected at station "b" and is rapidly mixed with the combustion products from section 2. Fuel/air injectors can be placed in ports C, E, F, H, J, L, N and P to vary stage residence times. The combustion processes in the subscale fuel-staging combustor are essentially one dimensional, which is an easily interpretable environment for defining the mechanisms and rates of the fuel-staging process. Since all of the combusted

gases must pass through the second flame zone, mixing impacts on the NO_x reduction process are avoided in this design.

Radial probing tests, before and after injection, have shown that fuel and air are rapidly mixed with the combustion products producing a uniform mixture downstream of the injector. Also, no backmixing of injected reactants into section 1 or 2 is observed. In addition, temperature probing tests along the length of the combustor have shown that the backfiring system reduces heat losses to a level where practical gas temperatures are achieved at the combustor exit.

A stainless steel water-cooled and quenched probe is used to extract solid and gaseous samples along the length of the combustor through ports A through Q as well as at the "exhaust" location, sample port O. In addition, ports A through Q can be fitted with glass viewports for flame observation or they can be used for thermocouple, suction pyrometer, ignitors and flame detector access ports. Continuous measurements of NO , CO , CO_2 , O_2 and UHC were taken with the following instrumentation:

NO/NO_x	TECO Model 10 (chemiluminescence)
O_2	Teledyne 326A (microfuel cell)
CO_2/CO	Anarad AR600R (nondispersive infrared)
CO	Anarad AR500R (nondispersive infrared)
UHC	Beckman Model 400 (flame ionization)

In addition to the continuous measurements, wet chemistry impingers and specific ion electrodes were used to measure $-\text{CN}$ and NH_3 for selected conditions. Solid samples were collected and proximate and ultimate analyses were obtained for selected conditions. Temperatures were measured by bare thermocouples, which were corrected, through comparison with suction pyrometer measurements at selected conditions.

Nominal running conditions were 16.1 kW (55,000 Btu/hr), 120 percent theoretical air at the exit, ambient temperature combustion air and 70 percent through 200 mesh Utah coal. The coal analysis is given in table 1.

RESULTS

To date, NO_x reductions of over 70 percent from baseline have been found on Utah coal in the fuel-staging combustor. The impact of stoichiometry, residence time and fuel fraction on NO_x reduction is discussed in the following paragraphs.

Stage Stoichiometry

Second-stage stoichiometry was found to be an important parameter in fuel staging. During the tests, stoichiometry was varied by fixing the fuel flow to each stage and varying the air flow to obtain a range of first- and second-stage stoichiometries. The final stage stoichiometry was held constant at 1.2. Load was fixed at 55,000 Btu/hr.

Fuel-staging results with injector locations F and J (see figure 3 for definition) are shown in figures 4 and 5. For comparison purposes, classical-staging results taken with the same combustor are also presented in figure 5. In this fuel-staging case, 50 percent of the fuel was injected at the second-stage entrance (fuel fraction of $f = 1$, ratio of first- to second-stage fuel flowrate). As with classical staging, the NO at the exit decreases with decreasing SR_1 and SR_2 . However, there are some important differences. For fuel staging, the injection of fuel in the second stage allows a much wider range of operating first- and second-stage stoichiometries to achieve the same NO level. For example, with fuel staging, the first stage can be run fuel lean, while the second stage remains fuel rich, a situation not possible with air staging. These conditions are highlighted by dashed lines in figure 5.

As can be seen in figure 5, NO levels are fairly insensitive to SR_1 , and are particularly insensitive in those regions where the second stage is fuel rich (i.e., $SR_2 \leq 1.0$). This can also be seen in figure 4, where the variation of NO for different SR_1 's is much smaller than the variation of NO with SR_2 . Thus, very significant NO reductions, over 60 percent relative to baseline levels, can be achieved while maintaining the first stage fuel lean. Under fuel-rich first-stage conditions, a maximum reduction of about 75 percent can be achieved.

Comparing the classical-staging results in figure 5 with the fuel staging results in figure 4 at equivalent fuel-rich-stage stoichiometry, it appears that the NO level is dominated by the richest point in the combustion system.

Comparing fuel-staging results to classical-staging results as a function of SR_1 in figure 5, fuel staging with $SR_2 \leq 0.8$ gives comparable NO at $SR_1 \leq 0.8$ and lower NO for $SR_1 > 0.8$. For the $SR_1 > 0.8$ fuel-staging cases, the fuel-rich-stage residence time (τ_2) is less than the classical-staging fuel-rich residence time (τ_1). In these fuel-staging cases, less of the combustor is operated under fuel-rich conditions for equivalent NO reduction. In summary, compared to classical staging, fuel staging is beneficial in regions where $SR_2 < 1$ and $SR_1 \geq 1$.

Stage Residence Time

A residence time comparison between fuel staging and classical staging was made in figure 5. Figure 6 presents the same fuel-staging data compared to advanced air staging at stations C and F (see figure 3 for a definition of staging locations). In this comparison the classical-staging first-stage residence time (τ_1 , classical) is equal to the fuel-staging second-stage residence time (τ_2 , fuel staging). This comparison shows that, for equivalent fuel-rich stoichiometry, $SR = 0.8$, and residence time, the classical-staging case gives a 40 percent reduction from baseline NO levels, whereas the fuel-staging case gives a 60 percent reduction from the baseline NO level. As shown in figure 6, to achieve the equivalent NO reduction, the first-stage SR_1 must be reduced to almost 0.4 in classical staging. Apparently, the NO decay process with fuel staging is more rapid than it is with classical staging.

This reduction of NO with residence time is more clearly shown in figure 7. It should be noted that, for the $SR_2 = 0.9$ case, the level and reduction of NO with residence time is insensitive to first-stage stoichiometry, SR_1 . Also for the $SR_1 = 1.2$ case, the fuel-rich second stage ($SR_2 = 0.9$) reduces the first-stage NO (expected to be 800 ppm) to exit levels of 500 ppm NO in roughly 0.33 sec second-stage residence time. Second-stage residence times of about 1 sec at these conditions reduces NO below 400 ppm. However, the major part of the reduction occurs for second-stage residence times of 0.33 sec or lower.

Figure 7 also shows the advanced air staging* exit NO variation for different first-stage residence times at fixed second-stage residence times. Comparing in figure 7, the $SR_1 = 0.8$ advanced air to $SR_2 = 0.9$ fuel-staging NO results at 0.33 sec fuel-rich stage residence time, it can be seen that fuel staging has better NO performance than air staging for low fuel-rich-stage residence times. The air-staging results are about 50 percent higher than the fuel-staging results at less than 0.33 sec residence time.

Fuel Fraction

Most of the fuel-staging data was taken at a fuel fraction of unity ($f = 1$), where equal amounts of fuel were injected into the first and second stages. This f value was chosen as the nominal condition because the effect of fuel staging was expected to be significant and easy to see at this condition. Also, a very large range of first- and second-stage stoichiometry combinations could be explored. For higher fuel fractions, where less fuel is injected into the second stage, transport air requirements limited the range of stoichiometries which could be achieved. In addition to the $f = 1$ case, an $f = 3$ case was extensively tested.

Figure 8 compares $f = 3$ (75 percent of the fuel in the first stage) and $f = 1$ (50 percent of the fuel in the first stage) NO results for the nominal-stage-length F-J injector location (see figure 3). At low SR_2 the NO emissions for $f = 3$ are roughly independent of SR_1 and are at about the same level as for $f = 1$. As SR_2 increases, NO emissions are less for $f = 3$ than for $f = 1$ under fuel-rich, first-stage conditions. Under fuel-lean, first-stage conditions ($SR_1 \geq 1$), NO emissions are comparable for $f = 1$ and $f = 3$.

The comparability of $f = 3$ and $f = 1$ emissions for lean SR_1 is encouraging evidence that for the fuel-staging conditions of interest ($SR_1 \geq 1.0$), the NO reduction potential of fuel staging is not sensitive to fuel fraction.

*Air staging with air added at stations b and c (see figure 3).

DISCUSSION

Testing in the idealized combustor has shown that fuel staging can significantly reduce NO emissions to levels lower than air staging for equivalent fuel-rich residence time and stoichiometry. This NO reduction can be achieved even when the first stage is fuel lean, as long as the second stage is fuel rich. The major parameter for fuel staging is the second-stage stoichiometry. Optimum NO reduction is achieved for second-stage stoichiometries of 0.6 to 0.8. Maximum NO reduction from baseline was found to be 72 percent. For lean first-stage conditions, the mean reduction from baseline was 66 percent.

Table 2 presents results from this effort and the primary results from several fuel-staging studies (references 2, 3, 6, 7) which preceded and paralleled this effort. These results were briefly discussed in the introduction. The results of Wendt (reference 2) and Myerson (reference 3) are small-scale doped gas studies, where some of the reactor exit conditions were substoichiometric. These nonpractical, substoichiometric combustor exit conditions were not run in the present study. Some of the recent Mitsubishi Heavy Industries (MHI) (reference 6) and Energy and Environmental Research Corporation (EERC) (reference 7) results were obtained under more practical excess air exit conditions. As discussed in section 1, the MHI pilot-scale data (reference 6) was obtained in a 23-MW (80-million Btu/hr) tangential-coal-fired research furnace. Because of flow and mixing difference and also a fuel difference, a direct comparison between the MHI and present data cannot be made. However, presently the MHI data is the only constant-load coal flame processed by a coal flame data available to which the present subscale test results can be compared.

Consistent with MHI and other results presented in table 2, SR_2 has been shown to be a dominant parameter with optimal NO reductions achieved for $SR_2 \leq 0.8$. The maximum percent reduction achieved by the different investigators for coal, oil, and gas fuel under superstoichiometric exit conditions is also consistent with the results of this study.

MHI showed that, after 0.2 sec, the fuel-staging NO level had reached the asymptotic low level (reference 6). The small slope of the fuel-staging NO results with residence time found in this study, shown in figure 7, support this result.

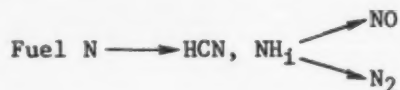
As shown in table 2, MHI used an f of 2 in their coal tests, which is between the cases run in this study. In this study, the amount of fuel injected into the second stage was less influential on NO than second-stage stoichiometry. The correspondence of MHI and the present results over a range of f supports the limited importance of f to NO reduction.

Consistent with EERC results (reference 7), in this study first-stage stoichiometry was found to be less influential on NO emissions than second-stage stoichiometry.

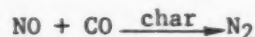
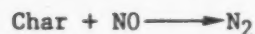
Based on the results of this study and others, the fuel staging process has similarities to air staging. The trends of NO with second-stage

stoichiometry are similar to trends of NO with first-stage stoichiometry for air staging. Based on prior air-staging results, it may be speculated that the NO reduction process could be a result of the following homogeneous and heterogeneous reduction paths:

Homogeneous



Heterogeneous



For the gas, oil, and coal fuel results presented in table 2, it is expected that the levels of soot and char in the NO reduction zone will be quite different. The correspondence of NO reductions for the different fuel types suggest that the gas-phase processes might be dominating the NO reduction with the heterogeneous processes only contributing in a secondary manner. However, it is possible that, in the case of oil or coal fuel, heterogeneous NO reduction processes become more significant and homogeneous processes become less significant, leading to the same overall percent NO reduction as observed for gas fuel. Certainly, homogeneous processes are dominant in the case of gaseous fuels. Presently, data analyses and further experiments are underway to help define the mechanisms and rates of the fuel-staging process and to identify the relative significance of the homogeneous and heterogeneous NO reduction paths.

ACKNOWLEDGMENT

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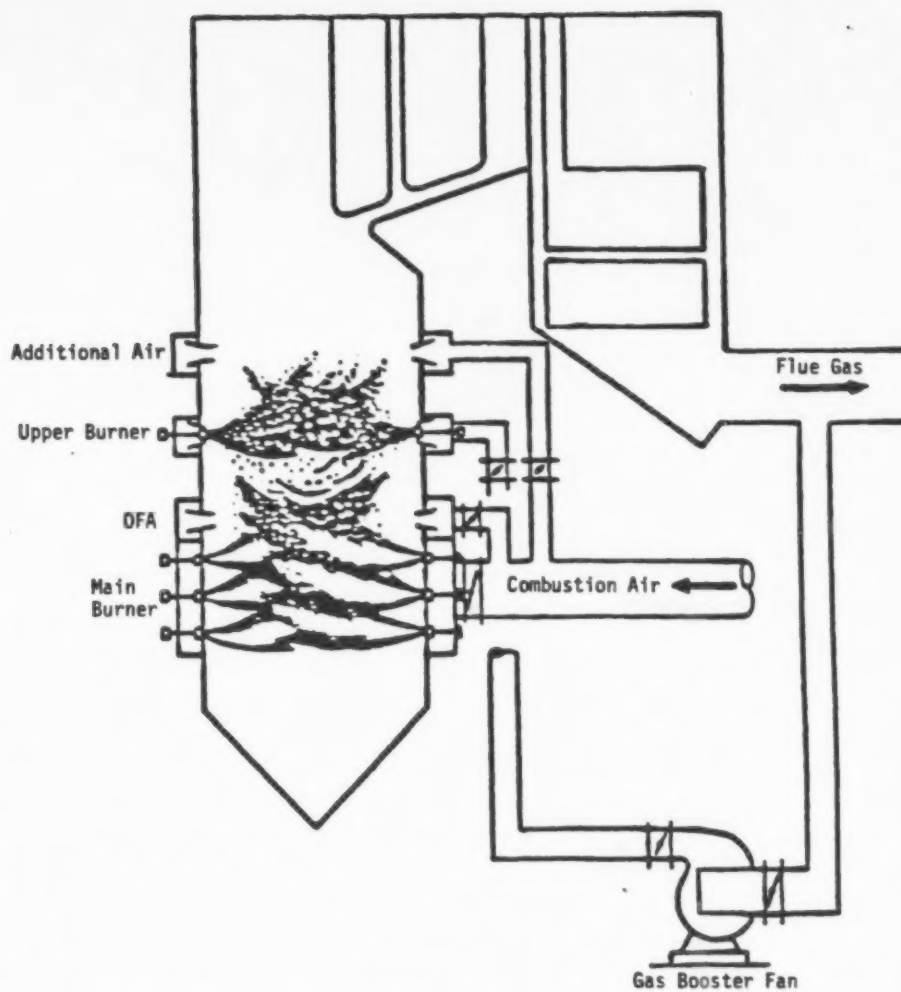
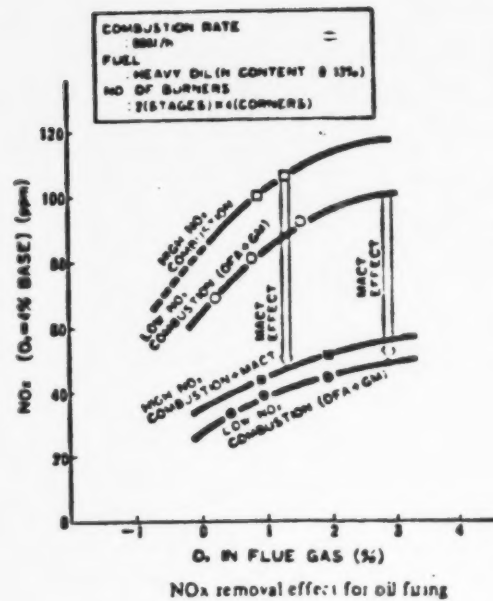
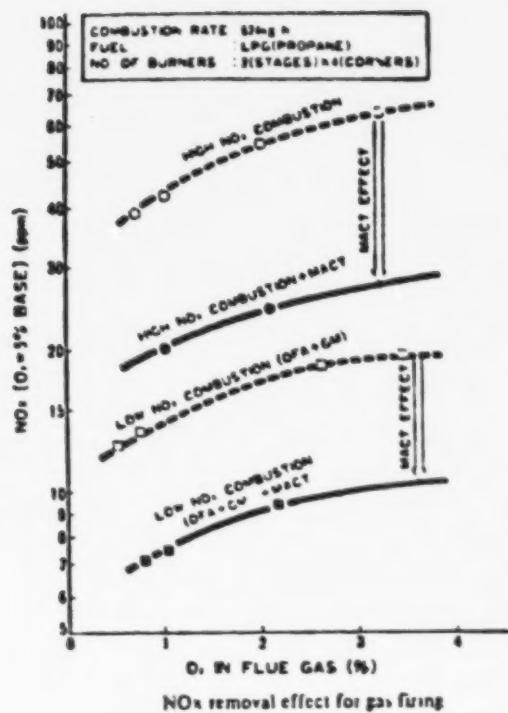


Figure 1. Schematic of the fuel-staging approach applied to a pilot-scale furnace.



MACT: Mitsubishi Heavy Industries' term for fuel staging.

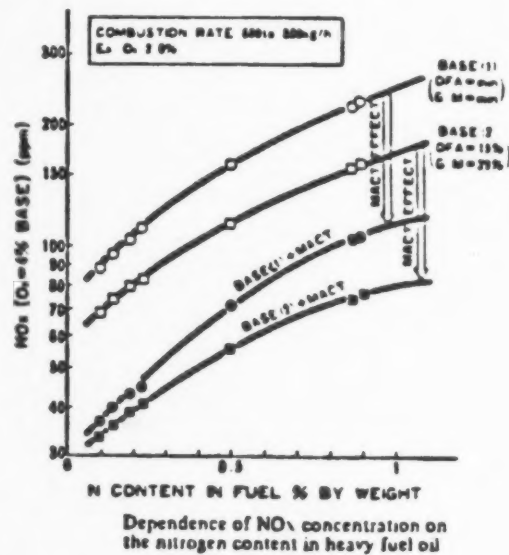
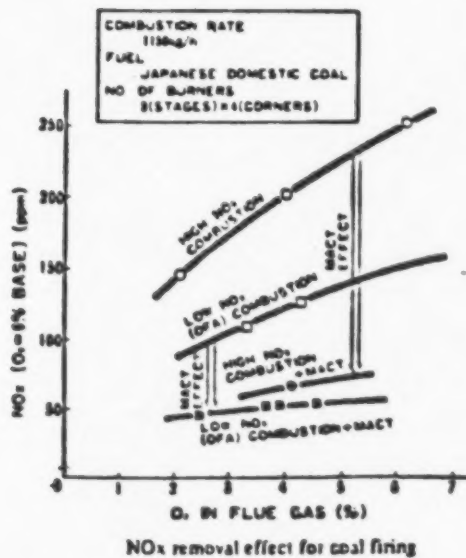


Figure 2. Pilot-scale fuel-staging and conventional-firing NO results.

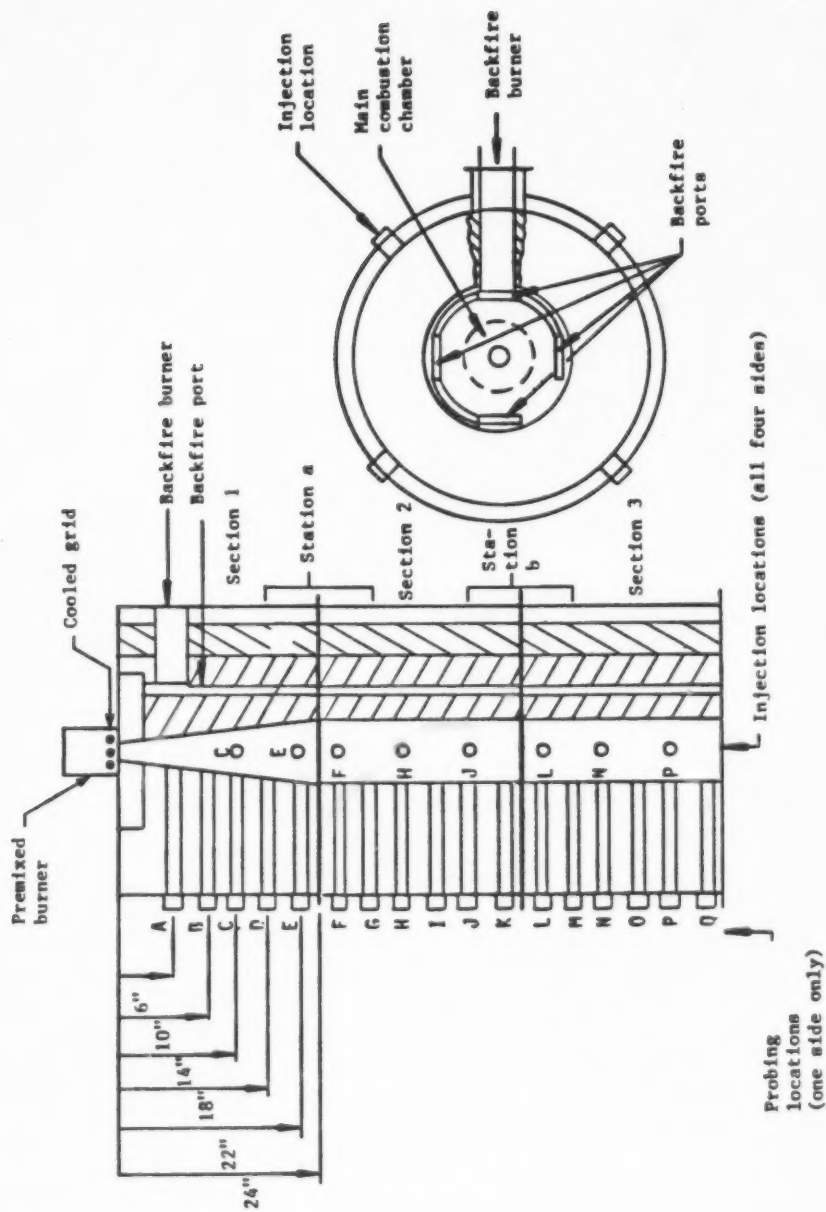


Figure 3. Fuel-staging combustor schematic.

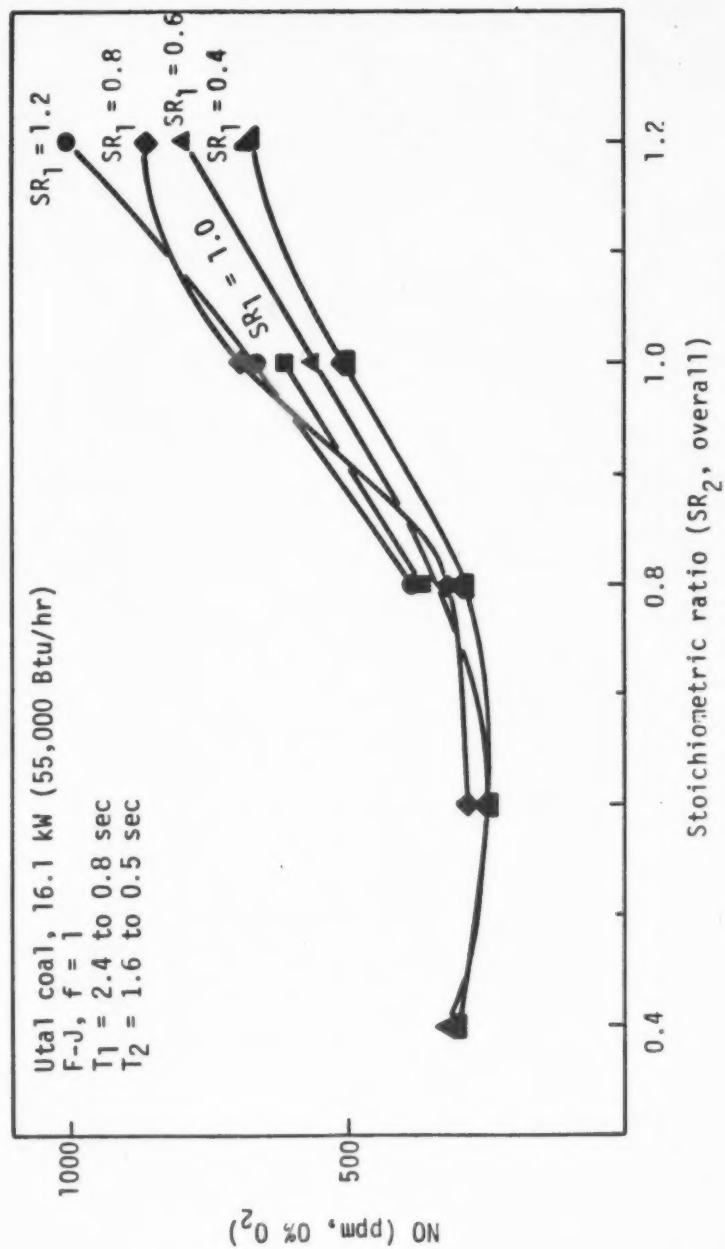


Figure 4. Fuel-staging NO versus SR_2 — injectors at F-J.

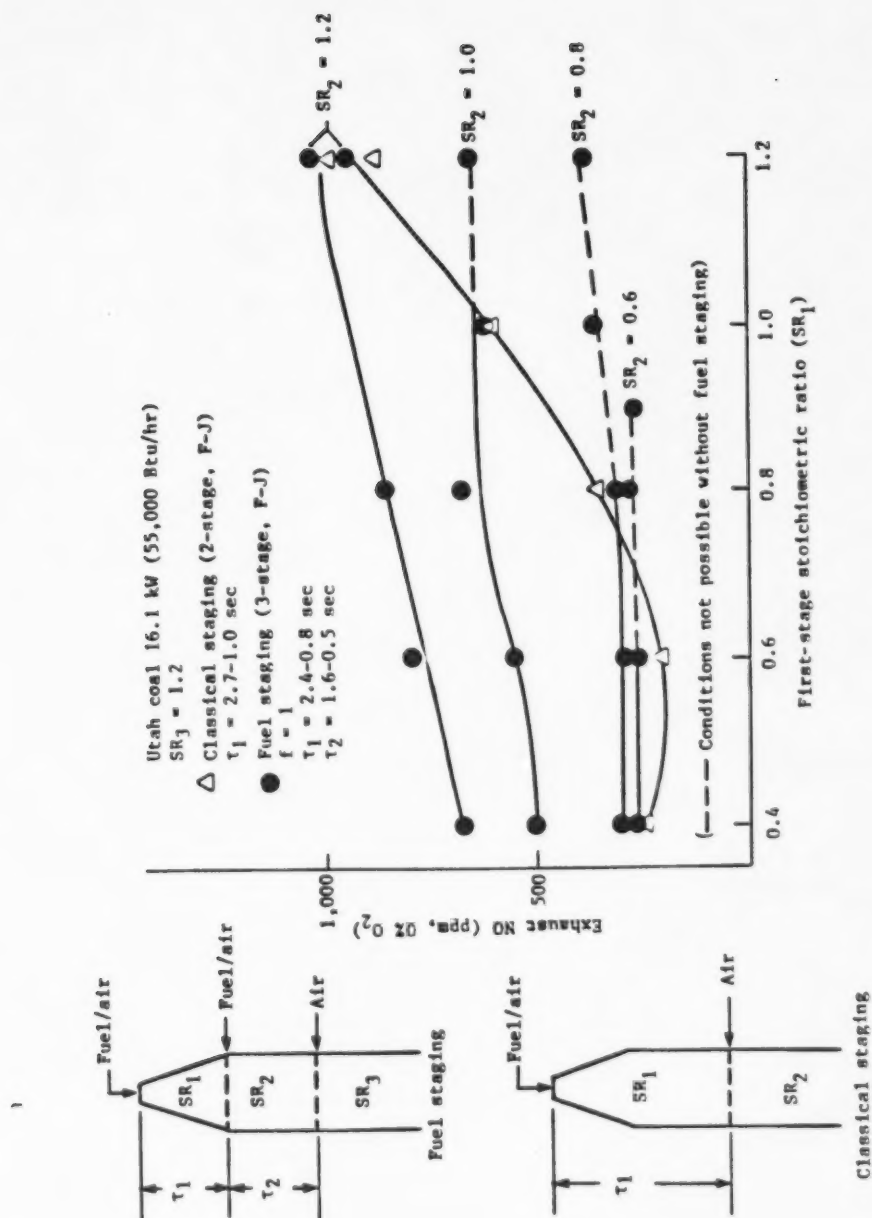


Figure 5. Fuel-staging and classical-staging NO versus SR_1 .

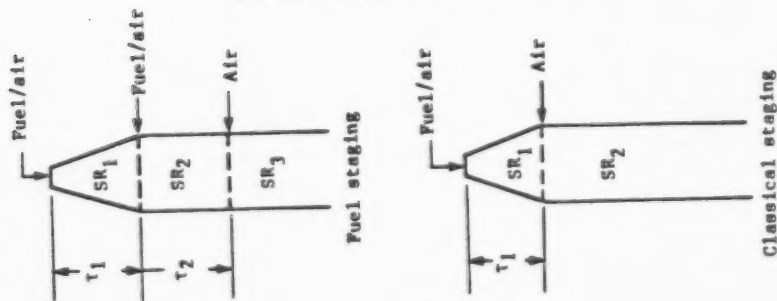
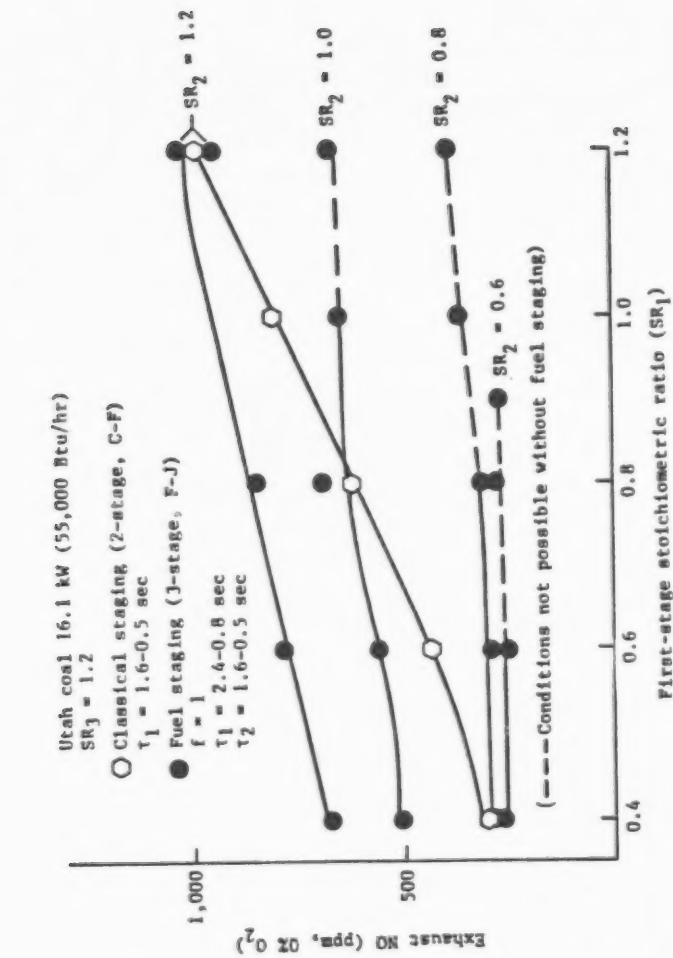


Figure 6. Fuel-staging and classical-staging NO versus SR_1 .

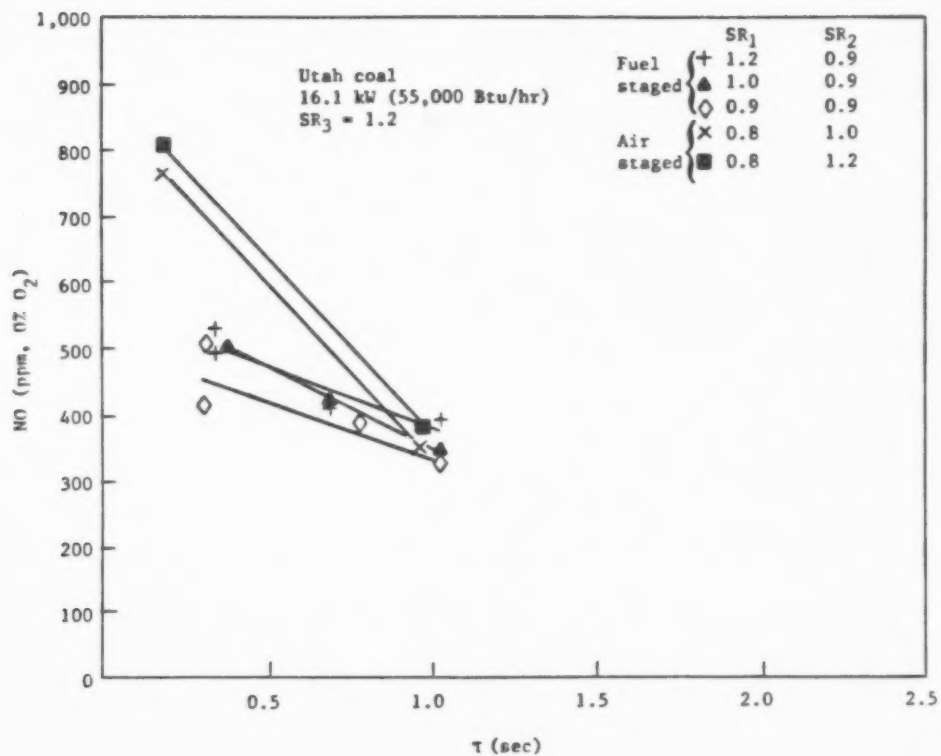


Figure 7. Fuel- and air-staging NO versus second- and first-stage residence time, respectively.

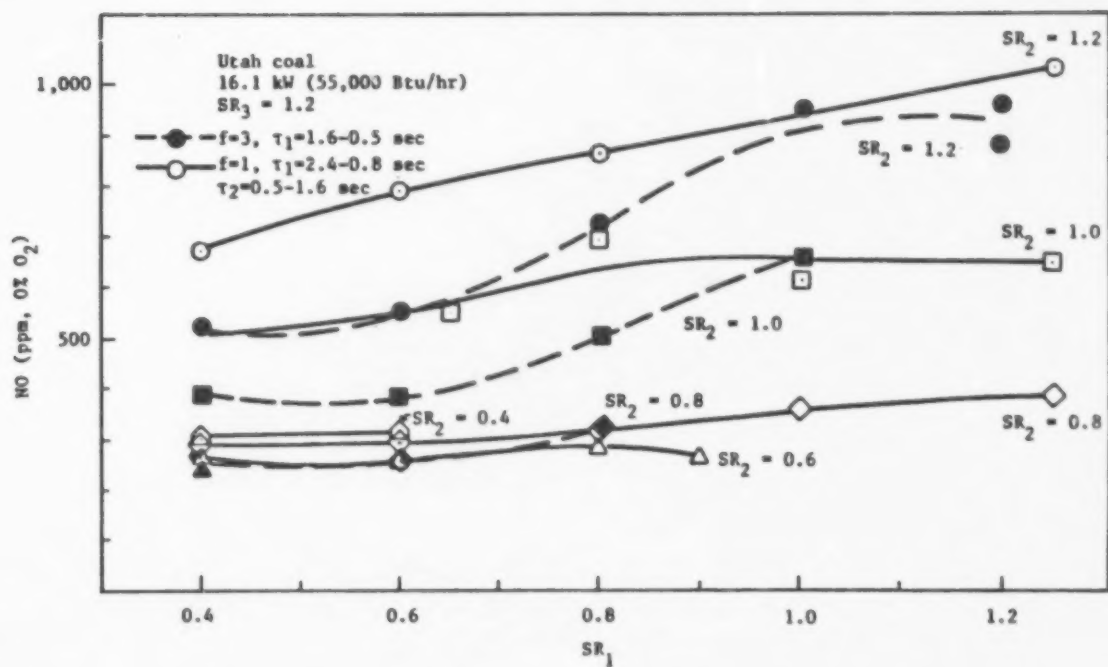


Figure 8. Comparison of $f = 3$ and $f = 1$ fuel-staging NO results versus SR₁ — injectors at F-J.

TABLE 1. UTAH COAL ANALYSIS

Utah Coal Analysis (Weight Percents)		
	As Received	Dry
M (Moisture)	5.57	--
A (Ash)	9.31	9.86
VM (Volatile Matter)	39.84	42.19
FC (Fixed Carbon)	45.28	47.95
Btu/lb	11,716	12,407
C	66.32	70.23
H	4.78	5.06
N	1.27 ^a	1.34
S	0.97	1.03
O (Diff.)	11.78	12.48

Temperatures K (°F)		
Ash Fusion	Reducing	Oxidizing
Initial deformation	1,522 (2,280)	1,561 (2,350)
Softening (H-W) ^b	1,656 (2,520)	1,694 (2,590)
Softening (H-1/2W)	1,683 (2,570)	1,722 (2,640)
Fluid	1,756 (2,700)	1,756 (2,700)

^aContent has ranged from 1.15-1.58 percent N in various analyses

^bH = cone height; W = cone width

Source: Plateau Mining, Price, Utah. Starpoint no. 1 Mine Hiawatha, Seam.

TABLE 2. FUEL-STAGING RESULTS

	Wendt (Reference 2)	Myerson (Reference 3)	Takahashi (Reference 6)	Clark (Reference 7)	This Study
Secondary fuel	CH ₄	Gaseous and liquid hydrocarbons	Coal, oil, gases	Gas, coal	Utah coal
Percent NO reduction	~50	~80	>50	>50	>50
SR at maximum NO reduction	0.67 - 0.5	0.6 - 0.3	0.8 - 0.2	0.9 - 0.8	0.8 - 0.6
Temperature (K)	1,800	1,200 - 1,600	>1,400*	--	1700
Residence time (seconds)	--	0.13	0.1*	--	>0.33
Importance of initial NO concentration	Not significant for NO >1,000 ppm	Not significant for NO >1,000 ppm. Some change in reduction at 580 ppm.	Not significant	Significant for NO=148 ppm and coal as secondary fuel.	Not significant for NO >500 ppm
Comments	Laboratory-scale results. Substoichiometric conditions at exit.	Laboratory-scale results. Substoichiometric conditions at exit. At high T, reduction is improved.	Pilot- and sub-scale results.	Subscale results. Initial gas flame processed by coal or gas.	Subscale results.

*Propane fuel results only

IN-FURNACE CONTROL OF NO FORMATION IN
GAS- AND OIL-FIRED UTILITY BOILERS

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ABSTRACT

An advanced combustion process termed "In-Furnace Control of NO Formation" (ICNF) has been developed and patented by the Southern California Edison Company and investigated in conjunction with KVB, Inc., to assess its effectiveness in reducing NO emission from gas- and oil-fired utility boilers. This novel combustion process provides reductions in NO emissions by controlling the combustion stoichiometry in the different regions within a boiler furnace. The ICNF process is defined by two discrete combustion stages. In the first combustion stage, either natural gas or oil is burned under fuel-rich stoichiometry in order to control both thermal and fuel NO formation. The second combustion stage employs generally natural gas in either a fuel-rich or fuel-lean stoichiometry. In most applications, the fuel supply to the second combustion stage is less than 30 percent of the total fuel supply to the boiler. By properly selecting combustion stoichiometry and fuel type, a significant reduction in NO emissions is achieved. The ICNF combustion process was demonstrated in a 45 MW and 175 MW face-fired utility boilers. In each case, the advanced combustion process provided NO emission levels below those obtained with the use of conventional combustion modification techniques. The percentage reduction in emissions achieved by the ICNF process was found to vary depending upon the boiler design and, more importantly, the NO emission characteristics of the gas and oil fired burners used in a specific boiler.

INTRODUCTION

The Southern California Edison Company (SCE) has been engaged in the development and implementation of technologies aimed at reducing NO emissions from utility boilers since the late 1950s. Through the use of these technologies, SCE has reduced NO emission levels from its gas- and oil-fired boilers by more than 50 percent. These achievements established SCE as an industry leader in the field of NO emissions control.

Nearly all of the methods investigated by SCE for NO reduction involved a modification of the combustion process. Such technologies as staged combustion, through the use of burners-out-of-service (BOOS), and flue gas recirculation (FGR), were first evaluated and introduced by SCE to the entire industry. SCE's commitment to maintaining a high benefit-to-cost-ratio in the pursuit of NO reduction has led the Company to continue investigating combustion modification processes as opposed to a more costly flue gas treatment approach.

Among the novel combustion concepts recently investigated by SCE was the combined firing of natural gas and fuel oil in separate burners or burner elevations to effect a reduction in NO emissions. In the past, combustion modification technologies focused exclusively on burning a single fuel in the boiler. The practice of burning two different fuels simultaneously was generally performed in the same burner cell and termed combination firing. This practice was not utilized for NO control, but rather to enhance boiler availability when the desirable fuel was not available to meet 100 percent of the system loading requirements.

The concept of burning two different fuels for the purpose of NO control was first attempted by SCE at its Highgrove Generating Station in 1976. This program was conducted to assess the emission characteristics of Paraho Shale Oil which has a relatively high nitrogen content (2% by weight). The NO emissions obtained by burning the shale oil and a conventional low sulfur oil in separate burner elevations was considerably less than the NO emissions resulting from burning an equivalent blend of the two oils in all burners (Ref. 1). Additional experimentation with natural gas and shale oil confirmed the validity of the process and led to a patent award to SCE.

The simultaneous firing of gas and oil in two discrete combustion stages comprised the elements of the combustion process for the In-Furnace Control of NO Formation (ICNF). The process provided an alternate technology for NO reduction with an attendant improvement in operational flexibility. In view of the potential advantages of the ICNF process, a research program was initiated to identify variables that can influence the effectiveness of the process. This paper reviews the results of this research program and discusses the potential applicability of the ICNF process as a NO control measure for gas- and oil-fired utility boilers.

PROGRAM DESCRIPTION

The general objective was to examine advanced combustion techniques for the control of NO emissions from gas- and oil-fired utility boilers. Of special interest to SCE was the optimal use of natural gas in conjunction with low sulfur fuel oil for emission control. The need to optimize the use of natural gas for NO control was dictated by the following factors:

- . A recent court order requiring further NO reductions in the California South Coast Air Basin;
- . The escalating cost of natural gas; and,
- . The re-emergence of natural gas as a significant portion of the fuel mix.

The concern over the escalating cost of natural gas encouraged SCE to identify novel combustion processes that would allow NO levels that were comparable to natural gas firing when simultaneously firing oil and gas. SCE's interest in developing the new technology reflected the Company's commitment to minimize the emission of air contaminants associated with the production of electrical power. The specific program objectives were selected to:

- . Identify the NO reduction potential of the ICNF process;
- . Evaluate the effect of the ICNF process on boiler operation and heat rate;
- . Identify the effect of boiler design and operational parameters on the effectiveness of the ICNF process.

The test program to evaluate the ICNF process was conducted in two phases. The first phase was carried out on a two-burner elevation 45 MWe unit at SCE's Highgrove Generating Station while the second phase was completed on a four-burner elevation 175 MWe unit at SCE's Alamitos Generating Station. Both test programs were similar in terms of work scope to allow SCE to assess the effects of the differences in boiler design on the results of the ICNF process. Total test duration at each location was approximately six weeks.

Since the performance of the ICNF process on both test boilers was found to be essentially the same, the data presented in this paper are limited to the Alamitos test site. This selection was made since the Alamitos boiler is more representative of a large-scale utility boiler. Duplicating the NO reduction effectiveness of the ICNF process in two different boilers, however, lent credibility to the potential applicability of the process to a range of boiler sizes and designs.

The Alamitos Generating Station is a 2100 MWe gas- and oil-fired generating station owned and operated by SCE. Testing was conducted on Unit 2, a 175 MWe Babcock & Wilcox steam generator rated at 1,140,000 lb/hr

steam flow, with 1000°F/1000°F steam temperature and 2180 psig steam pressure. The boiler is a balanced draft, drum type utilizing 16 burners on the front wall in a 4 x 4 matrix. The oil burners are mechanically atomized, with a variable return flow system. The gas burners are B&W ring spud burners. Each burner is rated at approximately 110 MMBtu/hr. Hopper flue gas recirculation is provided for steam temperature control.

Test parameters were very carefully selected to allow characterization of those expected to have the greatest influence on the ICNF process. The parameters examined during the evaluation included:

- . Fuel split (ratio of gas-to-oil in the boiler)
- . Local and overall furnace stoichiometry
- . Burner-out-of-service (BOOS) pattern

The emission sampling was conducted at the economizer outlet upstream of the air preheater wheel to preclude leakage of the combustion air into the flue gas. Twenty-four stainless steel probes were used to sample the concentrations of NO, CO, CO₂ and O₂. These species were measured using (1) a TECO 10A chemiluminescent analyzer for NO; (2) a Teledyne Fuel Cell oxygen analyzer; and (3) Beckman NDIR analyzers for CO and CO₂. The instruments were calibrated periodically to insure the accuracy of the data.

Several boiler operating variables were recorded to identify the effect of the ICNF process on plant heat rate and overall boiler performance. These variables included superheater and reheater attemperation rates, stack exit temperature and excess O₂ level, and total fuel supply to the boiler. Operating differences were identified and documented for test conditions using the ICNF process and test conditions using conventional combustion modification techniques.

In order to implement the ICNF combustion process, it was necessary to devise methods to (1) distribute fuel disproportionately to burner elevations and (2) change the ratio of gas to oil. In both the Highgrove and Alamitos programs, individual gas burners were instrumented to provide gas burner pressure. The oil burners were likewise instrumented except that at Alamitos, only supply and return oil pressure for each burner elevation was provided rather than individual burner instrumentation.

THE ICNF PROCESS

The ICNF process investigated at the Alamitos and Highgrove Stations differs in two important ways from the conventional combustion modification technique of staged combustion using overfire air ports (OFA) or burners-out-of-service (BOOS). First, two discrete combustion stages are created in the furnace wherein the combustion stoichiometry of each stage is independently controlled. Second, the type of fuel burned in each stage is selected to enhance the emission reduction achieved. Combining the effect of controlling

the combustion stoichiometry in different stages within the furnace with the emission benefits of selectively burning different fuel types allows the process to achieve emission levels lower than those generally realized with conventional combustion modification techniques.

The use of discrete stages of combustion to control NO emissions is not a totally new concept. The first practical system employing this approach was commercialized by the John Zink Company in 1969 (Ref. 2). The system was given the tradename NOxIDIZER and was offered to reduce NO emissions from nitric acid plants. Early work for developing the combustion process was performed by Wendt, et al., (Ref. 3) who injected CO and CH₄ downstream of the flame zone of a Meker type laboratory burner and recorded significant reduction of NO emissions. Similar studies were also performed by Myerson (Ref. 4) which investigated the use of a second combustion stage to reduce NO emission from automobile engines. Most recently, the Mitsubishi Heavy Industry in Japan applied the two-stage combustion process to the control of NO emissions from utility boilers. The system was offered under the tradename MACT (Mitsubishi Advanced Combustion Technology) and was reported to reduce NO emission by as much as 50 percent (Refs. 5, 6, and 7). The combustion process was further extended by Hitachi Zosen to design the multi-stage combustion burner (Ref. 8) which defined two combustion regions within the burner flame to affect the control of NO formation.

The ICNF process closely complements the work of previous research. Through the selection of combustion stoichiometry and fuel type, the process offers unique features that allow its implementation to existing boilers with minimal equipment modifications. A schematic of the ICNF process is illustrated in Figure 1. The first combustion stage of the process begins in the lower portion of the furnace and is always operated in a fuel-rich condition. The second combustion stage can either be operated under fuel-lean (Figure 1a) or fuel-rich (Figure 1b) conditions. The process can therefore be implemented in two markedly different modes: the fuel-rich/fuel-lean staged mode (rich-lean mode), or the fuel-rich/fuel-rich staged mode (rich-rich mode).

To implement the ICNF process, either natural gas or fuel oil is introduced to the first combustion stage. The emission reduction achieved by the process is best realized, however, when a "dirty" (high nitrogen) fuel is burned in this stage. As such, a minimum emission benefit is obtained when natural gas is burned in the first combustion stage and the maximum benefit is realized when a high nitrogen containing fuel is used. In the second combustion stage natural gas is generally the fuel burned.

In the rich-lean ICNF mode, the first combustion stage is operated fuel-rich followed by a second fuel-lean stage (Fig. 1a), generally using all burners in the combustion process. Approximately 70-90 percent of the total fuel supply is introduced to the first stage with the remaining 10-30 percent provided to the second stage. The firing mode has the distinct advantage of achieving NO levels comparable to those obtained with conventional combustion modification techniques (OFA or BOOS) with all burners in service.

The mechanism by which the rich-lean ICNF mode affects the NO reduction is mainly dependent on the ability of the second stage effluent to penetrate and oxidize the fuel-rich combustion products from the first stage. Burning a small amount of natural gas in the second combustion stage preheats the air to a high temperature and thus improves its ability to penetrate and mix with the products of combustion from the first combustion stage. Thus, fuel oxidation is obtained at a relatively low level of excess O_2 . Reducing the amount of excess air supplied to the furnace enhances the effectiveness of first stage fuel-rich combustion in controlling NO emissions.

The fuel-rich combustion of oil in the first combustion stage provides two favorable effects: (1) control of both thermal and fuel NO production and (2) the production of NH_3 species which can act as a NO reducing agent. The nitrogen contained in the fuel is thus partially utilized to affect a reduction in the overall NO emission level. The production of NO reducing species (NH_2 , NH_3 , etc.) during the fuel-rich combustion of nitrogen-bearing fuels has been substantiated by several investigators including Axtworthy, et al. (Ref. 9) Kahn, et al. (Ref. 10), and Mansour, et al. (Ref. 11).

In the rich-rich ICNF mode, the combustion stoichiometry of both the first and second stages are maintained fuel-rich. To achieve this condition, selected burners are taken out of service and operated with air only (Figure 1b). In this ICNF firing mode, the fuel distribution in the boiler is approximately 70 percent in the first combustion stage and 30 percent to the second stage with sufficient air supply to the interstage or overfire air to complete combustion. While this mode approximates BOOS or OFA operation, the major differences are the stoichiometry of the stages and the firing of gas in the second combustion stage. These differences allow NO_x emission reductions that surpass the levels achieved with either BOOS or OFA operation.

The NO emission reduction realized in the rich-rich ICNF mode is primarily attributed to the combustion of the fuel, fuel-rich, in two discrete combustion stages. However, additional emission benefits are obtained by NO destruction mechanisms. The emission reduction achieved by the rich-rich mode is therefore the result of two distinct effects. The first effect is due to the control of NO formation through fuel-rich combustion. The second effect is due to the destruction of NO from the first combustion stage within the fuel-rich zones of the second combustion stage. The NO emission levels achieved by this ICNF mode are therefore lower than those obtained through the use of the rich-lean ICNF mode. The primary drawback of the rich-rich mode is the increased O_2 requirements caused by staging and the constraint on boiler load that may result due to fuel pressure limitations.

The destruction of NO through the processing of combustion effluents through fuel-rich flames has been the subject of extensive research in recent years. The exact mechanisms for the NO destruction are not totally understood. It has been postulated, however, that NO reacts with the free radical species abundantly produced in a fuel-rich flame to form molecular nitrogen. Recent studies by Fujisawa et al. (Ref. 12) suggested that the NO destruction occurs via several mechanisms involving CO, H_2 , and CH_4 . The mechanisms suggested for the transformation of NO to molecular nitrogen included the following:



The net effect of these reactions is the decomposition of NO to N₂, H₂O, and CO₂.

Operating the second combustion stage fuel-rich in the rich-rich ICNF mode takes advantage of the above-described NO destruction effects. Firing the second combustion stage on natural gas provides the species (CH₄, CO, H₂) needed for the destruction of NO. In addition, the gas is not a smoke producing fuel and as such it is suitable to staging without dictating an unreasonably high excess O₂ requirement. The oxidation of CO produced by the fuel-rich combustion of gas is a homogeneous gas phase reaction that is easier to complete. This provides an advantage over the heterogeneous oxidation of smoke caused by the fuel-rich combustion of oil. Therefore, the selective combustion of gas in this second stage provides important advantages that cannot be realized with the use of fuel oil.

The general ICNF process offers some important advantages over the conventional combustion techniques. With both OFA and BOOS, the inability of the additional air to complete the oxidation of the fuel dictates the need for high excess O₂ operation. This compromises the NO reduction effect of staging and imposes an efficiency penalty on the boiler. The stratification of combustion stoichiometry within the boiler furnace from fuel-rich to fuel-lean regions further undermines the effectiveness of staging. Furthermore, the requirement to take selected burners-out-of-service, in some applications, limits the maximum load capability of a boiler and thus compromises the operational flexibility of the unit.

The ICNF approach eliminates many of the constraints inherent with BOOS or OFA techniques. The process introduces two discrete combustion zones that are operated at different stoichiometries and can be operated with different fuel types to achieve the desired NO reductions. In the case of the rich-lean ICNF mode, the combustion stoichiometry in the first combustion stage is "uniformly" fuel-rich maximizing the effectiveness of staging. The complete oxidation of the fuel is provided in a uniformly fuel-lean region. The high combustion air preheat provided by the lean combustion of gas increases the effluent penetration and improves the effectiveness of fuel oxidation and smoke suppression. The complete oxidation of the fuel is performed at a relatively low temperature near the furnace exit to minimize NO produced in this final burnout zone. Since gas contains no fuel-bound nitrogen, the fuel-lean combustion of gas is possible without excessive NO production. Some

increase in thermal NO formation is experienced in the fuel-lean combustion stage. However, the fuel supply to this stage is a small fraction of the total and, therefore, the emission penalty is not sufficient to adversely affect the overall benefits of the process. With the rich-rich ICNF mode, the disadvantages are similar to those of the standard OFA or BOOS operation, however the NO reduction effectiveness is enhanced by the NO destruction mechanisms, consequently lower NO emissions are achieved.

RESULTS AND DISCUSSION

The ICNF process was first demonstrated in a 45 MWe unit and evaluated further in a 175 MWe unit. The data presented in this section were limited to the 175 MWe boiler since the boiler size is more representative of a large-scale utility application and the four-burner elevations provided more operational variables. The performance of the ICNF process in the two test boilers was consistent.

The test results are presented in three primary subsections. In the first subsection the NO levels achieved by the ICNF process are presented and compared to the emission levels obtained with conventional combustion modification techniques. In the second subsection the effects of the ICNF process on boiler operation and heat rate are discussed and the third subsection reviews the variables that influence the effectiveness of the ICNF process.

NO Reduction Capability of the ICNF Process

To evaluate the NO reduction capability of the ICNF process, testing was initially performed to obtain baseline NO emission data for natural gas and fuel oil under all-burners-in-service (ABIS) and staged (BOOS) combustion conditions. Subsequently the simultaneous firing of natural gas and fuel oil was conducted using the ICNF process. The NO levels obtained by conventional firing (single fuel supply to the entire boiler) and simultaneous firing of gas and oil in the ICNF process were then compared. The comparison of the emission levels was made during operation with all burners-in-service and with selected burners taken out-of-service for both the ICNF process and conventional combustion modifications. The NO data were obtained as a function of boiler load and at a minimum stack O₂. The minimum O₂ requirement was selected as the O₂ level below which excessive CO and/or smoke emissions occurred.

The results of the baseline testing are presented in Figure 2. These data show that under ABIS combustion conditions NO emission levels from natural gas firing are higher than from fuel oil. This result is of a special interest since natural gas contains no fuel-bound nitrogen but characteristically results in uncontrolled NO emission levels which are higher than oil emission levels. The result suggests that thermal NO production during gas firing exceeds the combined contribution of thermal and fuel-bound NO production during oil firing. Factors that may contribute to this behavior

primarily include the intense mixing characteristics between the combustion air and fuel in the gas-fired burners, and secondarily the low thermal emissivity of gas flames which enhances thermal NO formation.

The effect of the conventional combustion control method of BOOS on NO emissions is also presented in Figure 2. The data are provided for both gas and oil firing. The natural gas staging is achieved by taking the third row of burners (four burners) out-of-service. In the case of oil firing, every other burner is taken out of service in the top two burner elevations as shown in Figure 2.

BOOS operation is shown to be very effective in reducing NO emission from the test boiler. The emission levels for gas and oil firing appeared to be for the most part comparable. The reduction in NO emission achieved by staging ranged between 30 to 50 percent depending on the boiler load and the fuel-fired (gas or oil). In every case BOOS operation increased the excess O_2 requirement to achieve operation with no CO and/or smoke emissions.

The baseline data show that NO emissions increase with the increasing boiler load. This is a typical behavior reflecting the enhanced thermal NO formation associated with the higher furnace heat release rate at high loads. As expected, the sensitivity of NO to load is reduced for staged combustion conditions since thermal NO production is inhibited by the fuel-rich combustion environment. This reduced sensitivity is most pronounced on oil fuel.

The advantages of using the ICNF process to control NO emissions are illustrated in Figures 3 and 4. The data presented in Figure 3 compares the ICNF process to the conventional ABIS firing of gas and oil. This particular ICNF mode was established by firing the bottom three rows of burners on fuel oil and the top single row on natural gas. The firing rate of each burner elevation was uniformly distributed with 25 percent of the total fuel on a Btu basis introduced to the top burner elevation as natural gas and 75 percent of the fuel introduced to the bottom three elevations as fuel oil. The firing condition is thus a limiting case of the rich-lean ICNF process.

The data presented in Figure 3 show that in the ABIS mode of combustion (no staging) the ICNF process provides a significant NO emission reduction over conventional gas and oil firing, even with the two stages operating at the same stoichiometry. Two mechanisms have been identified to explain this ICNF performance. The first mechanism results from the fact that the firing of gas in the top burner elevation permits the operation of the boiler at a lower furnace excess O_2 than for oil fuel. This reduces the NO contribution from oil firing and thus produces a corresponding reduction in NO emissions. Lower O_2 operation with gas firing is possible since the fuel has inherently lower smoking tendencies than oil especially in an oxidizing atmosphere. Furthermore, the gas burns in compact flames which precludes flame impingement on furnace walls or the convective passages, consequently, the production of smoke due to thermal quenching is minimized.

The second mechanism contributing to the low NO operation is associated with the introduction of nitrogen-free fuel to the top furnace elevation. Due to the thermal gradient in a boiler furnace, invariably more combustion air is supplied to the top burners. As a result the fuel combustion in this region occurs at a "locally" high excess O_2 level. This maldistribution of air promotes fuel NO production when firing fuel oil in the upper elevation thus causing the NO contribution of this elevation to be larger than from other burner elevations. Replacing fuel oil with gas eliminates the fuel NO production in this region and thus reduces NO emission level achieved.

The effects on NO emission levels of operating the boiler in the rich-lean and rich-rich ICNF modes are presented in Figure 4. The emission levels for the ICNF firing are compared to the conventional combustion modification technique of staged firing with BOOS for both gas and oil. Data for three ICNF firing configurations are presented. The first configuration tested the rich-lean ICNF mode using all burners-in-service and burning natural gas in the second combustion stage at fuel-lean stoichiometry. The remaining rich-rich ICNF configurations incorporated the fuel-rich combustion of natural gas in the second stage. To implement this ICNF mode, either the third or fourth elevation of burners was taken out-of-service.

The NO data presented in Figure 4 clearly showed that the rich-rich ICNF mode can achieve NO levels that are substantially lower than those obtained with the conventional methods of NO control (BOOS). Furthermore, the data indicated that the rich-rich ICNF mode enhanced the level of emission reduction achieved compared to the rich-lean mode. Minimum NO levels were achieved with the rich-rich ICNF mode by taking the fourth row of burners-out-of-service such that the combustion of oil and gas is performed in sequence with no interstage air addition. In spite of this low emission performance, this firing configuration necessitated higher excess O_2 requirement which compromised boiler efficiency. An optimum balance between the excess O_2 requirement and NO levels was achieved by taking the third row of burners-out-of-service. This ICNF configuration resulted in NO and excess O_2 levels that are below levels achieved with the BOOS firing configuration generally used by SCE. Using the rich-lean ICNF process with all burners-in-service produced NO levels comparable to the standard BOOS operation, however, the low load excess O_2 level was inexplicably high. This ICNF mode thus provided the advantage of restoring all burners-in-service, while maintaining low NOx operation.

In the rich-rich ICNF mode NO reductions are the result of two complementary effects. The first effect results from the control of NO "formation" in the first and second combustion stages through the use of fuel-rich combustion. The second effect is the result of the destruction of NO formed in the boiler within the fuel-rich zone of the second combustion stage. The use of interstage air between the first and second combustion stages (taking the third row of burners-out-of-service) compromises the NO destruction effect of the second combustion stage and results in an increase in NO emissions. The interstage air addition, however, results in a lower excess O_2 operation which may be required to maintain acceptable heat rate.

The rich-lean ICNF process displayed the capability of achieving NO levels comparable to those obtained with BOOS operation while restoring the boiler operation to all burners-in-service. The process further demonstrated

that the use of the rich-rich mode provides NO levels substantially lower than those obtained with the standard BOOS operation. Depending on the firing configuration, the furnace excess O₂ requirement of the ICNF process can be lower than levels obtained with conventional low NO firing modes thus improving boiler performance and possibly plant heat rate.

Effect of the ICNF Process on Boiler Operation

Key boiler operating variables were monitored during the test program to identify the effect of the ICNF process on boiler performance. The variables examined included (1) superheat attemperation, (2) reheat attemperation, (3) flue gas stack temperature and (4) flue gas excess oxygen level. The reheat attemperation rate was closely monitored since it has a significant impact on the plant heat rate. The rate of attemperation was estimated using the attemperator valve control loading pressure which provided, on a relative basis, a reasonable indication of the amount of attemperation used. The attemperation rate data (lb/hr) were not readily available and as such the change in plant heat rate resulting from the use of the ICNF process was not quantitatively determined. Monitoring of the flue gas stack temperature and excess O₂ was performed to quantify the improvement or degradation in heat absorption within the boiler as a result of changing the firing configurations. Sootblowing procedures were monitored to assure reasonably similar furnace cleanliness conditions during the test runs.

The operating data were monitored during the program to compare the performance of the ICNF process to the performance resulting from the firing of either natural gas or oil. Figures 5 and 6 present the attemperation rate data for the superheater and the reheater, respectively, and Figure 7 provides the flue gas stack temperature data. The data are provided at two load levels (140 and 170 MWe) to insure that trends are not load dependent but rather relevant over a broad range of operating conditions. The gas and oil firing data are presented for the firing configuration (BOOS) which achieved the lowest NO emission level. The ICNF data, on the other hand, are presented for two firing configurations that resulted in low or minimum NO emission levels. The first rich-rich ICNF configuration (third row of burners-out-of-service) provided low-NO operation at a reasonably low excess O₂ level. The second rich-rich ICNF configuration (fourth row of burners-out-of-service) provided the minimum NO levels achieved but necessitated higher excess O₂ operation.

The attemperation rate data show that through the proper selection of the firing configuration the ICNF process can essentially eliminate the need for attemperation in both the superheater and reheater. As expected, the effectiveness of the process was more pronounced at full load operation than at part load, however, the need for attemperation at the 140 MWe was completely eliminated. The process thus provided a means of potentially improving plant heat rate while maintaining low-NO operation.

The reduction in attemperation rate achieved by use of the ICNF process compared to the standard BOOS configuration used with gas firing is attributed primarily to the high thermal emissivity of oil flames. Compared to gas

firing, improved heat absorption in the furnace cavity is obtained in the ICNF process since at least 66 percent of the total boiler thermal input results from fuel oil combustion. The fuel-rich first stage oil combustion provides luminous flames which further enhances the heat absorption in the lower furnace elevation.

Comparing the ICNF process reheat attemperation rates to those resulting from oil firing show that, for the third burner elevation out of service, the performance of both the oil and ICNF process is comparable. However, for the fourth burner elevation out of service the ICNF process provides a sizable reduction in attemperation rate. This reduction is mainly attributed to the concentration of the heat release in the lower portion of the furnace. The combustion of oil with the fourth burner elevation out of service is, in most applications, not optimum due to excessive smoke emissions which in turn necessitates higher excess O_2 operation. The rich-rich ICNF process thus offers the advantage of reducing NO emissions below levels achieved with oil firing while at the same time reducing the reheat attemperation rate.

The flue gas stack temperature data presented in Figure 7 complemented the data obtained on the attemperation rate. In general, the ICNF process and oil firing produced a reduction in stack temperature compared to gas firing. This reduction reflected the improvement in heat absorption within the furnace as a result of firing oil.

One limiting consideration in using the ICNF process with the top row of burners-out-of-service is the inability to make steam temperature. It is therefore expected that the firing configuration to be used with the ICNF process will depend on the specific boiler application. Boilers that have difficulty meeting design steam temperatures may have a difficulty implementing specific firing configurations (fourth burner elevation out of service) of the ICNF process. Factors that may influence the selection of the firing configuration may therefore include: (1) the NO emission target, (2) maximum furnace excess O_2 that can be tolerated based on fan capacity limitations or heat rate penalty, and (3) the ability of the boiler to achieve design steam temperatures.

Variables Influencing the ICNF Process

Several variables were identified during the course of the study to influence the level of NO emissions achieved by the ICNF process. The most important of these variables were (1) combustion stoichiometry in the second combustion stage, (2) comparative stoichiometries of the first and second stages, (3) fuel type (oil or gas) used in the first combustion stage, and (4) furnace excess O_2 . The effect of these variables was documented as presented in the following discussion.

The effect of the second combustion stage stoichiometry on NO emissions is illustrated in Figure 8 for the rich-lean and rich-rich ICNF modes of operation. The rich-lean ICNF mode was implemented by introducing 10 percent

of the boiler fuel supply as natural gas to the second combustion stage while maintaining the air supply to this stage at 25 percent of the total. The lower three elevations were operated with 90 percent of the total fuel as oil. The resulting air to fuel ratio in the second stage was 277 percent of theoretical (or 177% excess air).

The rich-rich ICNF mode was implemented by operating one burner elevation on natural gas, two lower elevations with fuel-oil and either the third or fourth elevation with combustion air. Fuel-rich combustion in the second stage was achieved by supplying 34 percent of the total fuel requirement as natural gas to either the third or fourth burner elevation, while maintaining the air supply to every burner elevation at roughly 25 percent of the total. As a result, the combustion stoichiometry in the second stage ranged between 76 and 81 percent of the theoretical air.

The data in Figure 8 clearly show that operating the second combustion stage fuel-rich achieves lower NO levels than operating the same combustion stage fuel-lean. This improvement in NO reduction is believed to be attributable to two effects. The first is the control of NO production resulting from fuel-rich gas firing in the second combustion stage. The second is a result of NO destruction that occurs when the products of combustion from the first combustion stage are processed through the fuel-rich zone of the second combustion stage. The NO levels achieved when interstage combustion air is introduced between the first and second combustion stages (third row of burners out of service) are not as low as those achieved with the fourth row of burners out of service. This is due to the fact that interstage air addition undermines the fuel richness of the second combustion stage. The postulated mechanisms for the destruction of NO are associated with the interaction of NO with CO, H₂, CH₄ as discussed previously. Finally, operation in the rich-rich ICNF mode with selected burner elevations out of service drives the first combustion stage more fuel-rich than can be achieved with the rich-lean ICNF mode where all burners are in service. This further reduces the level of NO produced in the first stage.

Selecting the firing conditions for the ICNF process and in turn the stoichiometry in the second combustion stage is expected to be influenced by many factors. For example, if the primary objective is to achieve an emission reduction while maintaining all burners in service, the rich-lean ICNF mode would be the selected approach. On the other hand, if a maximum reduction in NO emissions is desired, then the rich-rich ICNF mode would be the preferred option. A tradeoff between NO emissions and boiler efficiency can thus be made to satisfy a specific user's need using one of the two ICNF modes.

The effect of the stratification of the fuel/air ratio on the NO emission level resulting from implementation of the rich-lean ICNF mode is illustrated in Figure 9. The figure presents the result of a series of tests where the amount of natural gas fuel burned in the second combustion stage is progressively reduced and replaced by fuel oil firing in the first combustion stage. The data thus show the change in NO emission as the first combustion stage is made more fuel-rich and the second combustion stage fuel-lean.

One interpretation of the data from this figure suggests that the NO reduction achieved by use of the rich-lean ICNF mode is the result of two competing effects. The first is a control of NO formation due to fuel-rich operation of the first combustion stage. This effect is illustrated by the progressive reduction in emissions as less natural gas is burned in the second combustion stage resulting in the progressively fuel-rich combustion of the oil. The second is a NO production effect associated with the lean combustion of natural gas. Since natural gas firing represents a small fraction of the total fuel supply to the boiler, the emission penalty associated with the gas firing is not sufficiently large to adversely affect the overall benefits of the process. The emission level achieved by the process, however, is the net effect of the NO reduction achieved by the fuel-rich combustion of oil and the NO production suffered by the fuel-lean combustion of natural gas.

Further refinement of the ICNF process appears possible by reducing NO production in the fuel-lean combustion zone. This objective can be met by the following modifications to the top burner elevation: (1) low-NO burners; (2) localized water injection; and/or (3) flue gas recirculation. The evaluation of some of these approaches may be performed by SCE in the near future.

The data provided in Figure 10 illustrate the effect of fuel type burned in the first combustion stage on NO emission levels achieved by the ICNF process. The data are provided for two firing configurations: (1) all burners-in-service with fuel biased 10 percent on top row and 90 percent on lower three rows (rich-lean ICNF mode); and (2) fourth burner elevation out-of-service (rich-rich ICNF mode).

The data show that the effect of fuel type on NO emissions for the ICNF process is determined by the firing configuration. In the case of the rich-lean ICNF mode, NO emissions at full load for gas and oil firing are essentially the same. At part-load, however, high excess O₂ operation experienced during oil firing enhances both the fuel bound nitrogen conversion to NO and thermal NO and results in emission levels for first-stage oil firing that are substantially higher than gas firing.

In the case of the rich-rich ICNF mode, the NO contributed by fuel bound nitrogen is more effectively controlled due to the fuel-rich combustion of oil. As a result, the NO emissions from oil firing are either comparable or in some cases lower than gas firing for the investigated boiler load range.

The data show that the firing of fuel oil in the ICNF process can produce NO emission levels that are lower than those obtained by staged gas firing. This result was viewed to be significant since it provided, for the first time, a means for fuel oil to become environmentally competitive with gas. A key factor that contributed to this performance was the ability to control, through the use of fuel-rich combustion, fuel bound NO production from oil firing. The fuel-rich combustion of oil provided two favorable effects: (1) control of both thermal and fuel NO production; and (2) the

production of NH_i species which can act as a NO reducing agent. The nitrogen contained in the fuel was thus partially utilized to affect a reduction in the overall NO emission level.

Other factors that may have contributed to the low-NO performance of firing oil in the first combustion stage compared to gas is the higher thermal emissivity of oil flames. This is suspected to have resulted in reducing the peak furnace temperature during oil firing and in turn thermal NO production. The improved heat absorption within the furnace cavity obtained during oil firing is substantiated by the lower superheat/reheat attemperation rate and stack exit temperature.

The effects of furnace excess O_2 on NO emissions for both the rich-lean and rich-rich ICNF modes are illustrated in Figure 11. The data are for a boiler operating load of 140 MWe and show an increase in NO emissions with high excess O_2 operation. This performance is typical of the behavior experienced with other conventional combustion modification techniques for NO control. One notable advantage of the ICNF process, however, is the moderate increase in NO emissions with O_2 . In most combustion systems operating with conventional NO controls (BOOS and OFA), the increase in NO with O_2 varies between 35-40 ppm per one percent increase in O_2 . For the ICNF process, the NO emissions increase averaged 27 ppm per one percent increase in O_2 . The relatively low sensitivity of NO to O_2 variations during the use of the ICNF process provides a desirable operational flexibility that allows the maintenance of low NO operation over a range of furnace excess O_2 levels.

SUMMARY AND CONCLUSIONS

The ICNF process offers an attractive approach for reducing NO emission and potentially improving the heat rate performance of gas- and oil-fired boilers. The process provides a level of NO emission control that exceeds the emission reduction capability of conventional staged combustion techniques. Heat rate improvement is provided by the ICNF process by reducing minimum excess O_2 requirement, attemperation rate and stack exit temperature.

The effectiveness of the ICNF process in reducing NO emissions is best illustrated in Figure 12 by comparing the lowest NO levels achieved by the process to the minimum emission levels provided by the staged combustion of oil and gas. These data show that the emissions from the ICNF process, while burning 66 percent of the total fuel supply as oil, are lower than the emissions achieved with staged gas firing. The result is significant since it identifies a new approach where limited combustion of natural gas allows NO levels from oil firing to approach those achieved by gas firing. The ICNF process further provides the added advantage of reducing NO emissions achieved by the staged combustion of oil by an additional 30-40 percent.

Several conclusions can be reached based on the presented data. The most significant of these conclusions are the following:

- . The simultaneous firing of gas and oil in the ICNF process provides NO emission levels below those achieved by conventional staged combustion.
- . Creating two discrete combustion stages within the boiler furnace and selecting the combustion stoichiometry and fuel type burned in each stage are key factors contributing to the NO reduction achieved by the process.
- . The NO reduction achieved by the ICNF process is the result of two complementary effects -- (1) control of NO formation through the optimum use of staged combustion and (2) destruction of NO by the processing of the combustion effluents in fuel-rich regions within the furnace.
- . The use of the ICNF reduces NO emissions sensitivity to variations in excess O₂ and thus permits operation over a range of O₂ with low NO performance.
- . Important operating variables that affect boiler efficiency were favorably influenced with the ICNF process.

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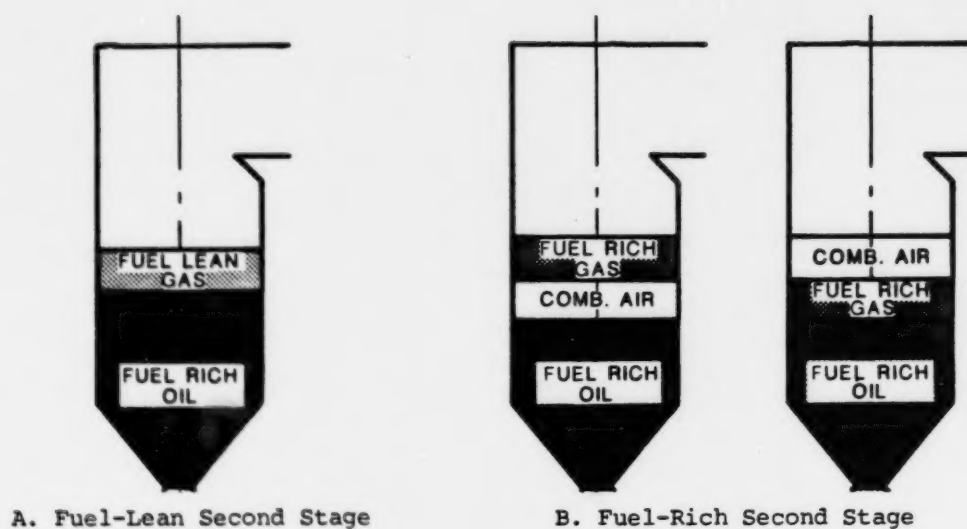


Figure 1. Firing configurations of the ICNF process.

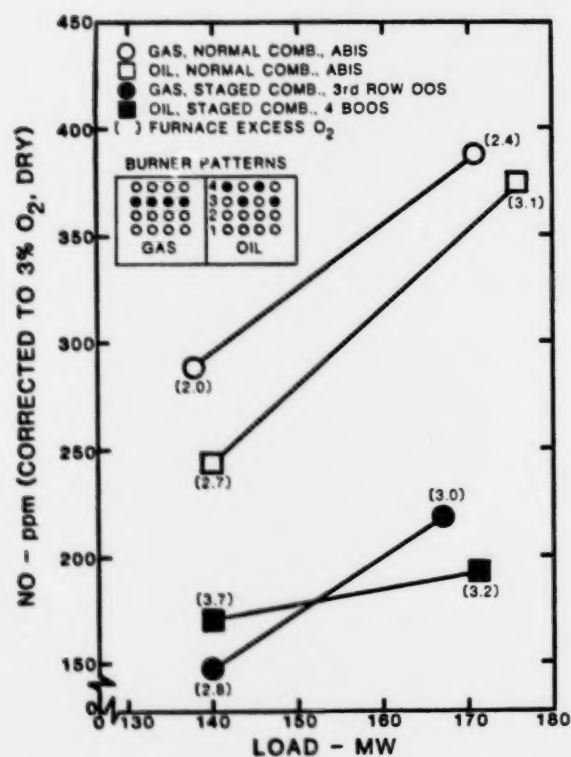


Figure 2. Baseline NO emissions for Alamos Unit 2.

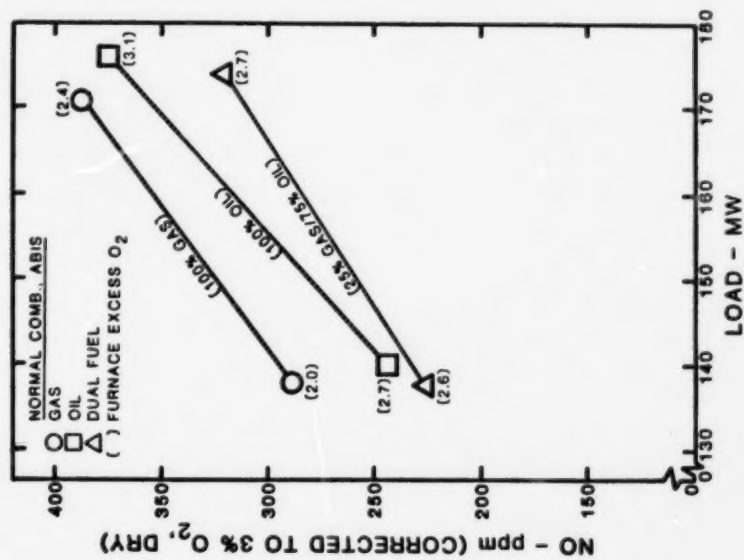


Figure 3. Effect of ICNF process on NO emissions during normal firing (ABIS).

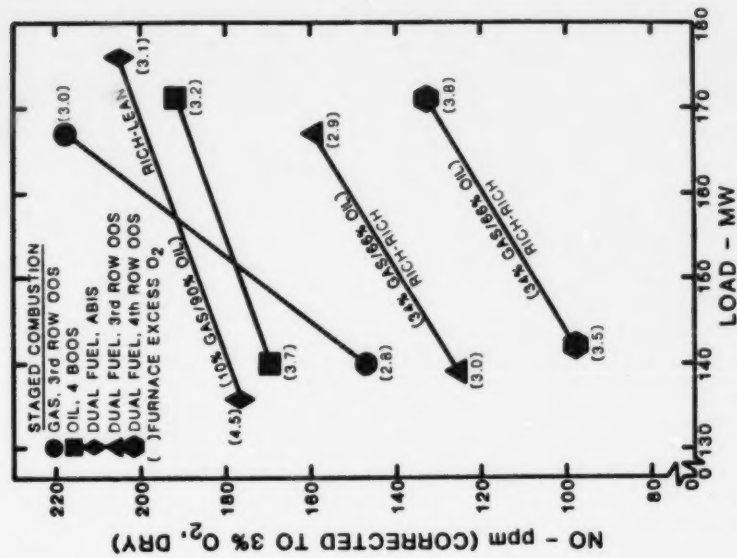


Figure 4. Effect of the ICNF process on NO emissions during staged combustion.

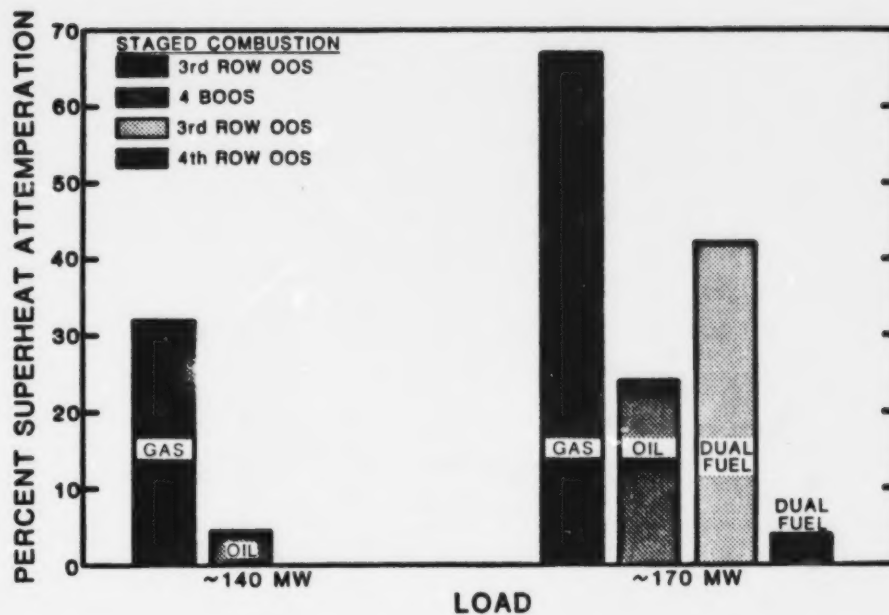


Figure 5. Effect of the ICNF process on superheat attenuation rate.

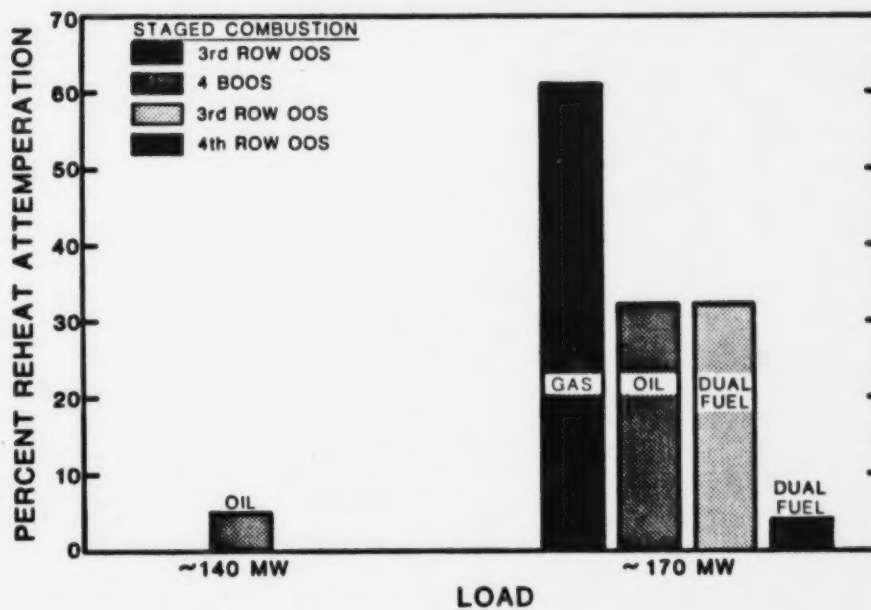


Figure 6. Effect of ICNF process on reheat attenuation rate.

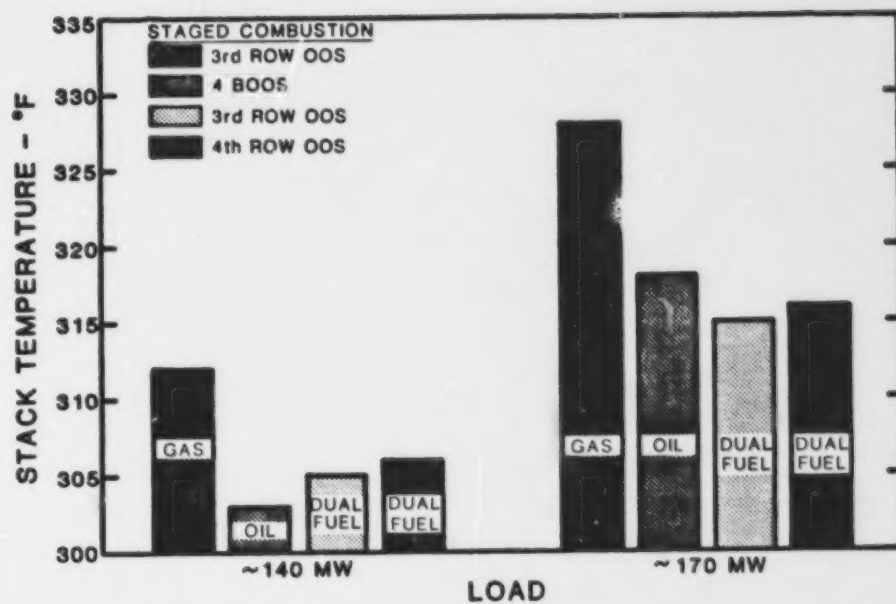


Figure 7. Effect of the ICNF process on flue gas stack temperature.

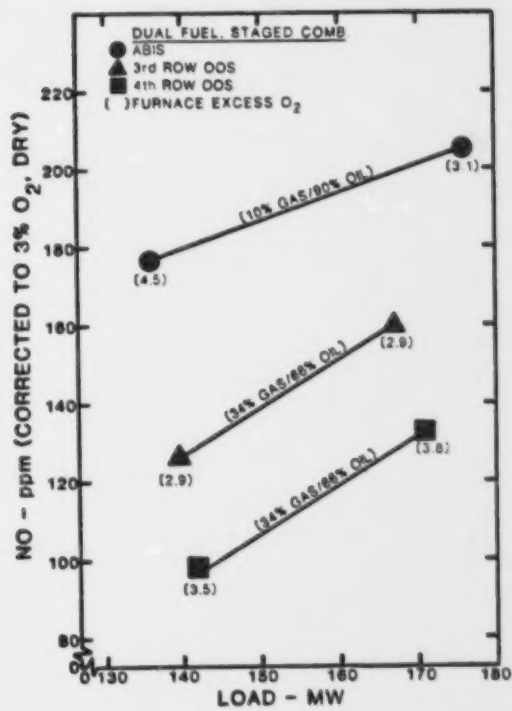


Figure 8. Effect of second-stage combustion stoichiometry on NO emissions from the ICNF process.

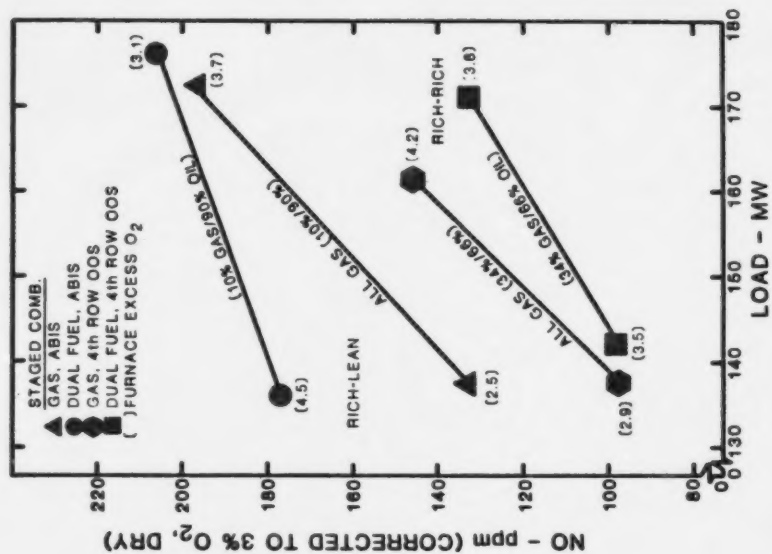


Figure 9. Effect of relative stoichiometries of the first and second combustion stages on the NO emission level achieved by ICNF process.

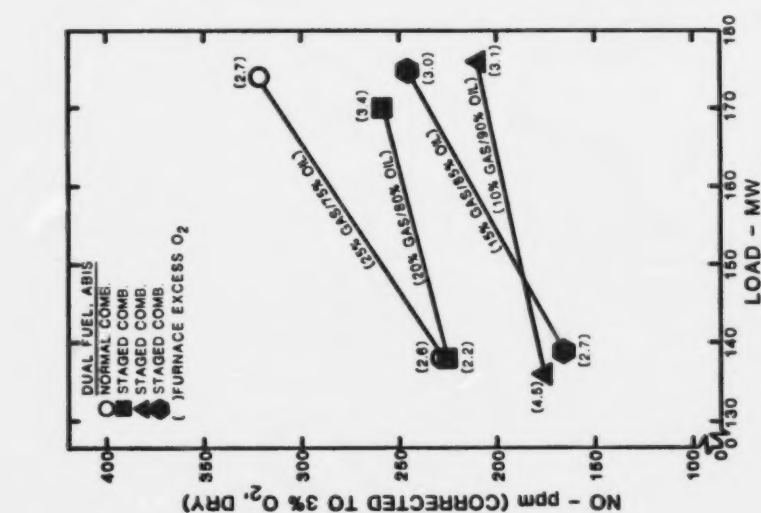


Figure 10. Effect of fuel type burned in the first combustion stage on NO emission level achieved by ICNF process.

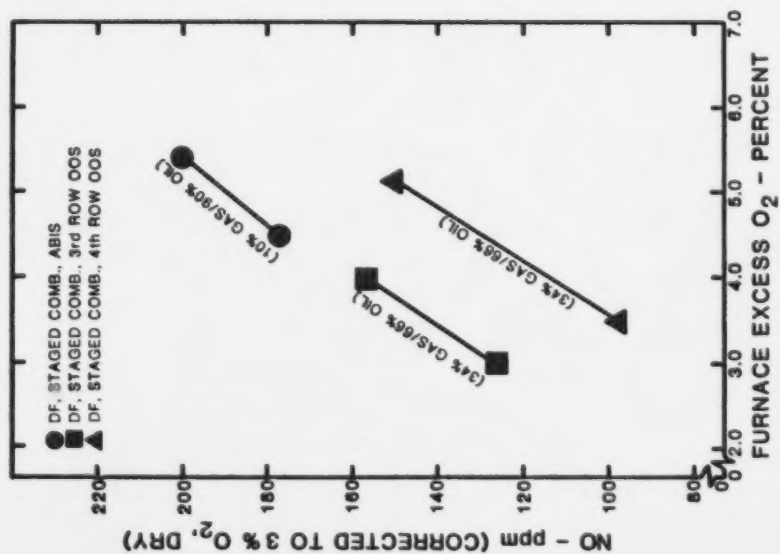


Figure 11. Effect of furnace excess O₂ on NO emissions during the use of the ICNF process.

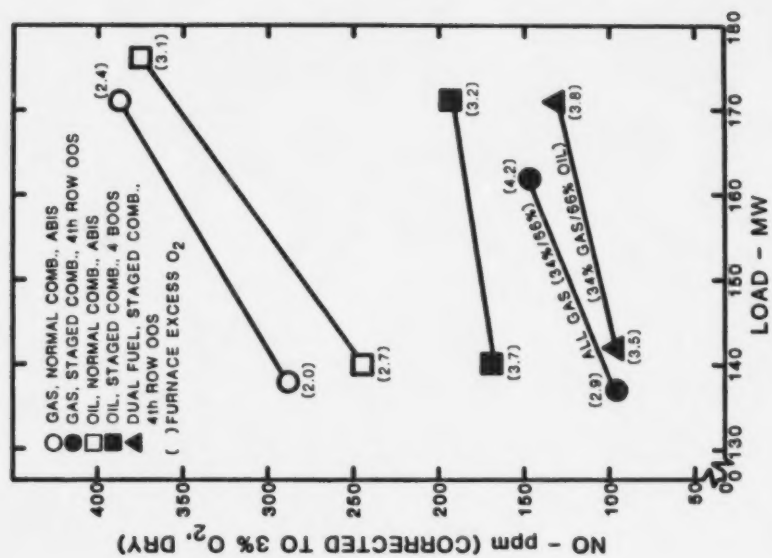


Figure 12. Assessment of the emission benefits of the ICNF process.

A REVIEW OF IN-FURNACE NO_x REDUCTION
AND SO_x REDUCTION BY SORBENT INJECTION

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ABSTRACT

This is an introduction to the technological development of the process known variously as in-furnace NO_x reduction, reburning, and/or fuel staging. It includes a review of past work where NO_x that had been formed in flames was subsequently eliminated by reacting with fuel. Work on gasifiers, combined cycles employing gas turbines with fired boilers, experimental burners, a boiler simulator, a full-scale utility boiler, and cement kilns has contributed to the understanding. Various United States and foreign organizations have made contributions to the development of the process.

The chemical activity of the fuel reducing and subsequent air completion zones gives a chance for the gases to equilibrate at NO_x concentrations commensurate with much lower temperatures. The chemical equilibrium of the various species at the temperatures where the reactions may occur gives a picture of what is obtainable. However, it must be kept in mind that, as the temperature falls, the gases reach regions where, even though the equilibrium favors low NO_x, the reactions are slow. The in-furnace NO_x reduction zone occurs at approximately the same temperatures for which SO_x absorption by injected limestone is effective. Equilibrium values for sulfur species of interest indicate that calcium sulfate formation may require operation at furnace exit temperatures below those common in utility boiler operation. Both in-furnace NO_x reduction and LIMB (Limestone Injection through Multi-staged Burners) may be improved through low furnace exit temperatures.

Practical aspects of furnace design impact the pollutant reduction technologies because of limitations due to heat transfer surface, volume, and temperature requirements. How in-furnace NO_x reduction can be adapted to cyclone, tangential, and opposed-fired boilers is discussed, along with the potential impacts of individual boiler design factors and fuel characteristics.

In-furnace NO_x reduction has been experimentally measured with pulverized coal, oil, or gas used as the additional fuel. Possible implementation techniques are discussed. Coal is, by far, the most economical fuel, but may restrict the technique because of primary coal transport, injection difficulty, carbon carryover, or a limited amount of NO_x reduction achieved.

INTRODUCTION

In-furnace NO_x reduction is a system for removal of NO and NO_2 from gas streams by injection of fuel into combustion products at temperatures of 1200°C or slightly higher, followed (after a suitable residence time and energy extraction) by the addition of enough air to complete the combustion at final temperatures of less than 1000°C . The process, which is known as in-furnace NO_x reduction, fuel staging, Mitsubishi Advance Combustion Technology (MACT), etc., is being developed in the United States and in Japan by various organizations (1, 2, 3). It shows promise of making NO_x emission reductions of 50 percent or more at reasonable costs. In the United States there have been bench-scale tests, while in Japan there have been bench-scale, pilot-scale, and commercial tests. Application of a similar process to reduce the NO_x emissions from a nitric acid plant was patented in 1969 (4).

The process employs a reducing zone followed by an oxidizing zone. This in-furnace reduction process would follow normal combustion or it can be used in conjunction with various low NO_x burners, thermal De NO_x , selective catalytic reduction, or other processes.

The process takes advantage of the ability of nitric oxide (NO) to react with organic compounds at these temperatures. In the process, the NO is reduced to nitrogen (N_2), ammonia (NH_3), nitrogen-hydrogen radicals (NH_i), or carbon-nitrogen-hydrogen compounds and radicals (NC_iH_j). This occurs under reducing conditions; therefore, it is necessary to subsequently add air to complete the oxidation. The amount of fuel used in the reduction process can range from as low as 5 percent to as high as 30 percent of the total fuel, depending on the arrangement. This fuel is burned and effectively used for steam generation, so use of fuel in the reduction step does not represent an energy loss.

A schematic of the system is shown in Figure 1. The in-furnace NO_x reduction process operates by providing fuel to the furnace through two kinds of burners. Most of the fuel is fired through the main burners. The main burners will usually be a low NO_x type. The remaining fuel is supplied through upper burners. The upper burners are operated without air addition or with a minimum of air addition; as a result, reducing conditions occur and the fuel reduces the NO and the slight amount of NO_2 which might be present. In this Figure, the upper burner fuel is introduced with recirculated flue gas. In large boilers it may frequently be necessary to use flue gas in order to ensure that the fuel achieves the necessary penetration without using an excess of air.

A zone or volume is provided for the mixing and reacting to occur. The time required is primarily a function of how well the mixing is done. Times of 0.1 second are given as being sufficient (2).

Following the reducing or de- NO_x ing zone, as it is sometimes called, sufficient air is added to complete the combustion. Enough air is added to

complete the oxidization of the fuel and supply the additional oxygen which is always necessary due to deficiencies in fuel/air distribution and mixing. The air is added well above the upper burners. Again, a volume or zone is required, this one to complete the oxidization. This zone may require a time of 0.1 second.

Several manufacturers are developing this technology. Each manufacturer has its own version which is different in detail but not in principle. Based on successful bench- and pilot-scale test results, Tokyo Electric Power Company is currently operating a 125 MW electrical unit with in-furnace NO_x reduction. This is a retrofit application. The oil-fired unit is demonstrating the commercial feasibility of the process (2).

The reduction of NO_x emissions by secondary fuel injection was reported by Wendt in 1973 (5). Further, in a combined cycle system, the reduction of NO_x emissions by the interactions between the exhaust from a gas turbine and boiler fuel fired with this gas has been reported (6). In this case, different levels of NO_x in the gas turbine exhaust were produced by adding ammonia to the natural gas fuel for the gas turbine. By firing with various levels of NO_x in the gas turbine exhaust, the researchers were able to establish, independently, the amount of NO_x formed in the boiler, and the amount of the gas turbine exhaust NO_x which was destroyed by the flames. Under the best conditions, fuel-rich, they were able to destroy nearly 50 percent of the NO_x in the gas turbine exhaust.

Extremely low NO_x emissions have been reported for in-furnace NO_x reduction processes. For instance, Figure 2 shows the results obtained on a coal-fired test unit (2). In this Figure, the reductions achieved from "high NO_x combustion" and from "low NO_x combustion" by overfired air, with in-furnace NO_x reduction, are shown. The initial levels are quite low. The reductions achieved with in-furnace NO_x reduction bring the NO_x emissions to very low levels.

Limestone injection for SO_x removal is a technology which may dovetail with in-furnace NO_x reduction. In this process much of the sulfur dioxide (SO_2) and all sulfur trioxide (SO_3) that occur are removed by injecting sorbents into the furnace. Materials which are used are oxides, hydroxides, and carbonates of alkali and alkaline earth metals. Most commonly, the metals are calcium, magnesium, or sodium. The species used is usually one of the following:

CaO
 Ca(OH)_2
 CaCO_3
 MgO
 MgCO
 Na_2CO_3
 NaHCO_3
 $x\text{Na}_2\text{CO}_3 \cdot y\text{NaHCO}_3$

The products are sulfates, sulfites, and, perhaps at times, sulfides of the respective metals.

The metals are usually injected at stoichiometric ratios of 1:1 to 3:1 or more of metal to sulfur. The magnesium and calcium carbonates should be injected where they will experience temperatures high enough for them to decompose to the metal oxides and carbon dioxide.

Following injection and decomposition to the oxide, the material proceeds through the boiler and, at some point, reacts with the sulfur oxides and oxygen to form sulfates and sulfites.

The materials are collected, along with the fly ash, in an electrostatic precipitator or baghouse. A baghouse may be the preferred method of operation, since the filtration of the gas containing unreacted sulfur dioxide through unreacted metal oxides will cause additional sulfur dioxide removal. Figure 3 shows a schematic of the process.

The reaction equilibrium is affected by:

- The stoichiometry
 - SO₃ concentration, or partial pressure
 - SO₂ concentration, or partial pressure
 - O₂ concentration, or partial pressure
- Temperature

The reaction rate is also affected by:

- Specific surface of the metal oxide
- Previous metal oxide reaction which may have consumed the available surface of the metal oxide
- Mixing and turbulence
- Particulate velocity relative to the gas
- Activity of the metal oxide

In this process, the sorbents are injected into the primary flame, the near regions to the primary flame, or at least in the furnace. The materials may be purchased pulverized, pulverized externally to the coal milling process or milled with the coal. Unless they are fed into the coal pulverizer and, therefore, injected into the central core of the flame, they must be pulverized in another device.

The process has been used in furnaces firing bituminous coals using traditional burners. In these cases, the flame temperatures, especially in face-fired boilers, may be so high that the materials, especially calcium oxide, become unreactive or "dead burned," as unreactive lime is sometimes called. This can be caused by partial fusion of the surface of the material,

reaction with fused ash components of the coal, or loss of surface area and reactivity due to other mechanisms.

Lignite, with its high moisture content, has a lower combustion temperature. This improves the operation of the process when limestone is used. Several researchers have had success applying this technique to relatively small utility boilers firing brown coal in Europe (7).

Distributed mixing burners are being developed and have been commercially introduced on a limited basis, both here and abroad. These burners result in lower temperatures and, as a result, the limestone can be calcined to lime without raising the material to excessive temperatures. The excessive temperatures would cause the CaO to sinter and the surface to become glassy, which would reduce the reactivity. However, additional time at high, but not excessive, temperature seems to improve the reactivity of the product. The temperature for sorption of SO_2 by the metal oxide is lower than the normal furnace exit temperature. However, this temperature is similar to the final burnout temperature for in-furnace NO_x reduction. Therefore, the two processes may fit together quite well.

CHEMICAL EQUILIBRIUM

The results of in-furnace reduction are remarkable. It would seem that some rather unusual reactions are taking place. However, Figure 4 shows that many of the results, as achieved in a number of processes, are very similar to the equilibrium values for NO at 3 percent O_2 and the temperature of the final oxidation zone. In Figure 4, the solid line is the equilibrium value for NO_x at 3 percent O_2 and the temperature given. The broken line is the least-squares fit line for the data of Johnson et al. (8).

In this process, coal was fired in a reducing zone with heat extraction. This zone was followed by air addition and final oxidation at reduced gas temperature. The work was done in a 4 million Btu/hr (1.2 MW thermal) pulverized coal combustion device. Johnson et al. found that NO_x can be either formed or reduced in the second-stage flame, and that the final NO_x is only slightly dependent on the first-stage NO_x , which in these experiments varied from almost zero to 300 ppm. The final NO_x is dependent upon the temperature at the flame front and the excess air in the secondary flame. This curve is the least-squares curve fit through about 60 data points obtained with four different coals using the optimum second-stage configuration. Additional data obtained with a different second-stage configuration also resulted in a NO temperature line which was very close to the equilibrium curve (8). Johnson et al. concluded that the study results indicate the desirability of operating the second-stage flame front at temperatures below those ordinarily occurring in the radiant sections of a utility boiler. These preliminary studies also indicated that, in spite of the low temperature requirements, a re-alignment of boiler heat transfer surfaces to maintain cycle efficiency will probably not be necessary.

This process has its similarities to in-furnace reduction, in that it employs the final oxidation of a fuel-rich flue gas stream at a low final flame temperature. It does not include the iteration of fuel-rich/air-rich zones as one would have in the case of a multistage burner coupled with in-furnace reduction. However, if the final NO_x can be substantially predicted from equilibrium considerations, such iterations are unnecessary to achieve low NO_x operation.

Data from other sources are shown in Figure 4. The shaded circle at 880°C was obtained from Figure 3 of Reference 2. This data was obtained in a cylindrical furnace using propane as the upper injection fuel. The triangle was obtained from Figures 3-41 and 3-42 of Reference 1. In this unit, the firing was with Utah coal at 55,000 Btu/hr (16.1 kW). These points both fall very close to Johnson's line. The data point shown as a hexagon is from the results obtained on a cement kiln where the exhaust gases are refired and the hot gases used to preheat the charge before it is fed to the kiln. In the cement kiln, the fuel was oil. The cement kiln data point is somewhat off the equilibrium line. Cement kilns normally have very high NO_x emissions, and this may represent an approach toward equilibrium from an initial value that was quite high. Also, at this low temperature the kinetics are not very fast.

It appears from Figure 4 that the results of in-furnace reduction, MACT, and Primary Combustion Furnace can be predicted from temperature and excess air considerations in the final oxidization zone. In the past it has been assumed that NO_x , once formed, became part of the emissions unless the flue gas was treated for NO_x reduction. The reaction kinetics in the regions of the furnace below about 1650°C (3000°F) were too slow either to contribute to the formation of NO or to allow NO to be removed if it existed in concentrations above equilibrium. Now it appears that the flame itself is a catalyst for reactions by which NO can be depleted. Certain radicals which are formed as an integral part of the combustion process react with the NO so it reduces. It also can be seen that final oxidation temperatures of 980°C (1800°F) and lower are required if the emissions are to be 100 ppm or lower. This may require redesigning furnaces and heat transfer surfaces. From the cement kiln result shown in Figure 4 and other data it can be seen that equilibrium values of NO are not always obtained. While final burnout equilibrium, based on temperature and O_2 concentration, is a rational goal, it may not be attainable in all industrial applications.

It is useful to discuss the retention of sulfur oxides by lime injected with fuel. In Figure 5, the equilibrium retentions for a lignite to which lime has been added are shown for a number of air/fuel ratios (10). The lower curve is for a fuel/air stoichiometric ratio of 1. It can be seen that the retention will not be significant until the temperature drops to about 900°C . Most of the condensed sulfur is in the form of sulfide. Fortunately, boilers do not necessarily operate at this air/fuel ratio. The two curves at 50 and 75 show what can be expected under fuel-rich conditions. Under these conditions, most of the sulfur, at equilibrium, would be in the

form of calcium sulfide (CaS). While this material is stable under reducing conditions, it would react rapidly when oxidizing conditions occur. Thus, to remove sulfur as sulfides it would be necessary to separate the condensed species, solids and liquids, from the gases before the final air was added. The two lines at 125 and 150 percent of stoichiometric air show equilibrium retention of about 70 percent at 1150°C. This is about the exit temperature of many furnaces.

There are a number of things to consider about the absorption of sulfur compounds. First, there are equilibrium calculations, and the result of these calculations would be the same if the CaO/S ratio was 1.1 or 15. The activity of solid species is not changed by the amount of the species. On the other hand, the sulfur retention percentage would increase if the sulfur level in the fuel were higher.

Since these are equilibrium calculations, the retention will be lower than the values shown. This will be true since the lime surface available for reaction may be depleted; the diffusion of SO₂ into the lime particle to unreacted areas is slow; and the condensed species, in the oxidizing region, is calcium sulfate, while the oxidized sulfur is in the form of sulfur dioxide. This implies that not only does the sulfur dioxide have to diffuse to the reaction site, but oxygen must also be available at the reaction site. The curves show that excess air, perhaps as high as 25 percent, is required for reaction and temperatures below 1150°C are required for good retention.

This requires relatively low furnace exit temperatures. The optimum temperature for sulfur retention in a fluidized bed is about 850°C. The retention drops off if the bed is operated above or below this temperature. We could assume that the reaction to limit sulfur oxide emissions will be substantial if the lime and the sulfur oxides have the opportunity to react between about 1100 and 540°C. At temperatures below 540°C, the reaction has been found to be quite slow in the absence of a liquid aqueous phase. In the furnace, the residence times may be 1 to 3 seconds which should allow ample time for reaction. However, in the convective passes the temperature drops quite rapidly to temperatures below 540°C. Thus, if the sulfur retention is not completed in the furnace, the opportunity for reaction is limited. Most of the successful commercial applications of limestone injection for sulfur removal have been in lignite-fired boilers in Europe which had furnace exit temperatures below 1100°C.

PRACTICAL ASPECTS OF FURNACE DESIGN

In-furnace NO_x reduction has been said to be implementable in existing utility boilers without changes in heat transfer surfaces, etc. However, the implementation of MACT (2) necessitated moving the windboxes and use of flue gas recirculation to ensure mixing of the upper fuel with the combustion products. Either of these by itself might require compensating adjustments in flows or heat transfer surfaces. They may have been implemented so as to compensate for each other.

The furnace exit temperature may, of necessity, be reduced in order to take advantage of in-furnace NO_x reduction. While NO_x reductions would be possible when operating at 1200°C , the reductions that may be required will necessitate temperatures of 1000 – 1100°C . How are these temperatures to be achieved in large furnaces? Derating units can be an effective method of reducing furnace exit temperature; on the other hand, it is a very expensive method. Such alterations as providing additional heat transfer surface, moving burners to lower positions in the boiler, and flue gas recirculation may be necessary in order to obtain the required temperature.

Alternate retrofits such as the one presented as the preliminary design for "The Primary Combustion System" (8) may be possible. A drawing of this design is shown as Figure 6. While this boiler is shown as a cylindrical device with the convective sections proceeding vertically above the furnace, this does not seem to be a fundamental requirement of either the PCF boiler or the in-furnace NO_x reduction. The process could be arranged with new burners located outside the existing furnace. These burners would have new energy extraction systems, water tubes, which would reduce the furnace temperatures. If the burners were operated fuel-rich, the final air would be introduced through slots around the burners. In a system more akin to in-furnace NO_x reduction or "MACT," the burners would operate air-rich and a reduction zone would be established above the top burner level, followed by a final oxidizing zone above that. Alternate schemes would require moving the burners to lower levels in the furnace, adding new heat transfer surfaces, etc.

Residence times of 0.1 second are said to be adequate for the reduction of NO . Neither the reducing zone nor the oxidizing zone seems to require excessive time, so that does not seem to be a problem. Reducing zones in furnaces have been viewed as potential corrosion zones. It may be, therefore, a requirement for in-furnace NO_x reduction that some air be supplied to shield the furnace in the reducing zone. This may require the introduction of low velocity air in this zone, introduced so it would flow along the walls. Alternately, if the fuel is properly introduced, it may be that the temperatures, 1200°C , in the reducing zone may be adequate to ensure that no untoward events occur.

IMPLEMENTATION

Experimental results have been reported in the literature which show the usefulness of in-furnace NO_x reduction. These data have been briefly reviewed here. There are a number of possible implementation techniques. Some of the more obvious techniques are shown in Figure 7. The possible applications include: (1) old utility boilers; (2) new utility boilers; (3) fuel-staging burners in industrial devices; (4) cement kilns employing preheat; (5) repowering boilers; (6) glass furnaces; and (7) cogeneration.

The implementation of in-furnace NO_x reduction in existing utility boilers offers a number of opportunities and difficulties. Cyclone-fired boilers are among the highest emitters of NO_x of any type of boiler. They

offer a different set of circumstances for infurnace NO_x reduction. The cyclones could be fired fuel-rich. Then, the boiler would look much like "The Primary Combustion Furnace System." Air would be added in slots or other devices around the cyclone exits. There has been much opposition to even the considering this type of operation of cyclones by the users and the manufacturer because of the potential for increased tube wall corrosion. It may be better to consider a traditional air-rich cyclone operation followed by a fuel-rich zone, than an air-rich zone in the furnace. In either case, implementation in a cyclone boiler seems like an attractive alternative to consider, since this boiler has high NO_x emissions as currently used.

Tangential boilers also offer a good candidate for study. While they usually have relatively low NO_x emission levels, they operate with a large circulation zone which may be ideal for mixing fuel into, while maintaining oxidizing environments at the wall.

Figure 8 shows how in-furnace NO_x reduction and limestone injection through multistage burners (LIMB) could be used together, and how they complement each other. In this pictured boiler, the furnace exit gas temperatures are 800° to 1000°C which are low, compared to current practice; but a boiler could be designed with such exit temperatures without any thermodynamic penalties.

Air and fuel are introduced in the primary flame zone. Of the fuel, 65 to 85 percent is introduced in the primary zone. Approximately the same percent of the total air flow will be introduced in the primary flame zone, since the fuel here will be burned with normal excess air. The burners may or may not be low NO_x burners depending upon whether or not it turns out that the final NO_x is a function of NO_x from the primary flame.

Above the flame zone, more fuel is introduced. With this fuel, flue gas is recirculated. The flue gas is used to impart sufficient energy to the stream to ensure adequate mixing with the combustion products. At this point, the temperature will be $1200 - 1300^\circ\text{C}$. This temperature is high enough to ensure that limestone is calcined ($< 900^\circ\text{C}$), but low enough that the limestone will not be "dead burnt". The limestone will be injected here.

Limestone selection and pulverizing is critical to the removal of sulfur oxides by this process. There has been quite a bit made of proper flame temperature to prevent "dead burning" and some study of the effect of milling. Very little has been said about furnace exit temperature, and almost nothing mentioned about the limestone source. All limestones are not created equal! In the reducing zone, the NO will be converted to NH_3 , HCN , and N_2 , while the limestone is converted to lime.

The final oxidization zone will be at $800 - 1000^\circ\text{C}$. It is difficult to see how either NO_x or SO_x can be effectively controlled if it is above 1100°C . In this zone, the NH_3 and HCN will be converted to NO and N_2 . The final NO will be dependent almost entirely upon temperature and excess oxygen. The SO_x will depend upon exit temperature CaO/S ratio, initial

sulfur in the fuel, CaO size and structure, and the degree of mixing of the limestone with the gases.

After the gases pass through the convective passes, economizer, and air heater, they will probably be cleaned by a bag filter. Baghouses will probably be the particulate removal devices of choice for two reasons. First, the use of a baghouse will cause the lime to remain in contact with flowing gas and cause additional removal of SO₂ even at the very low temperature. This reaction can proceed to a measurable degree in the baghouse because the lime will remain in contact with the gases for many minutes here, compared to the few seconds it will be suspended in the gas. Second, the lime in addition to removing part of the SO₂ will remove all of the SO₃ and would probably make the proper functioning of a electrostatic precipitator quite difficult.

This process will probably decrease NO_x emissions by 50 - 70 percent from the current levels experienced in pulverized coal firing, and reduce SO₂ emissions by 40 - 60 percent.

ACKNOWLEDGMENTS

The authors wish to express their appreciation for the assistance and direction given to this task by the Project Manager, R. E. (Bob) Hall of the United States Environmental Protection Agency.

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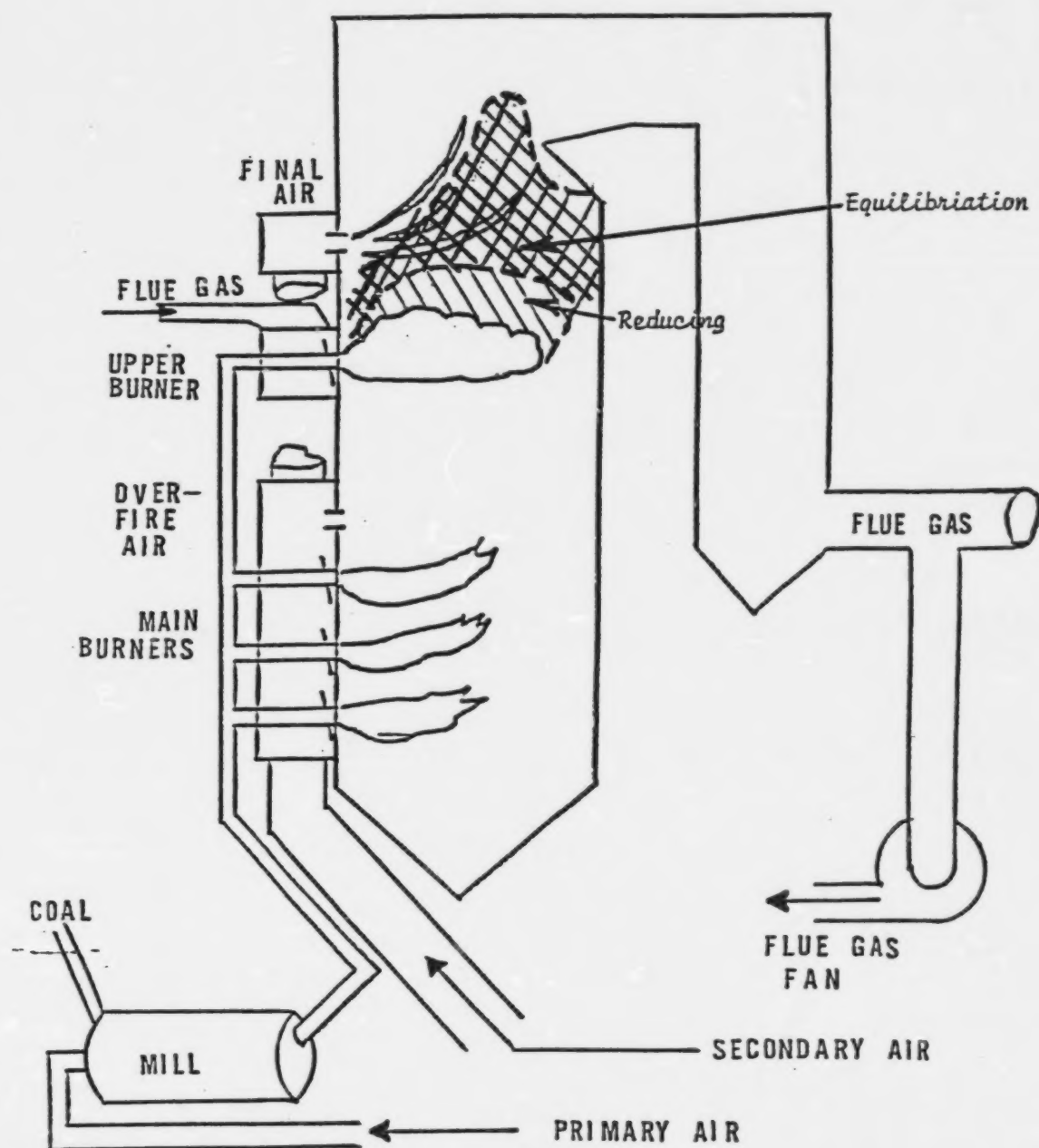


FIGURE 1. SCHEMATIC OF IN-FURNACE REDUCTION ON A COAL FIRED BOILER USING FLUE GAS RECIRCULATION

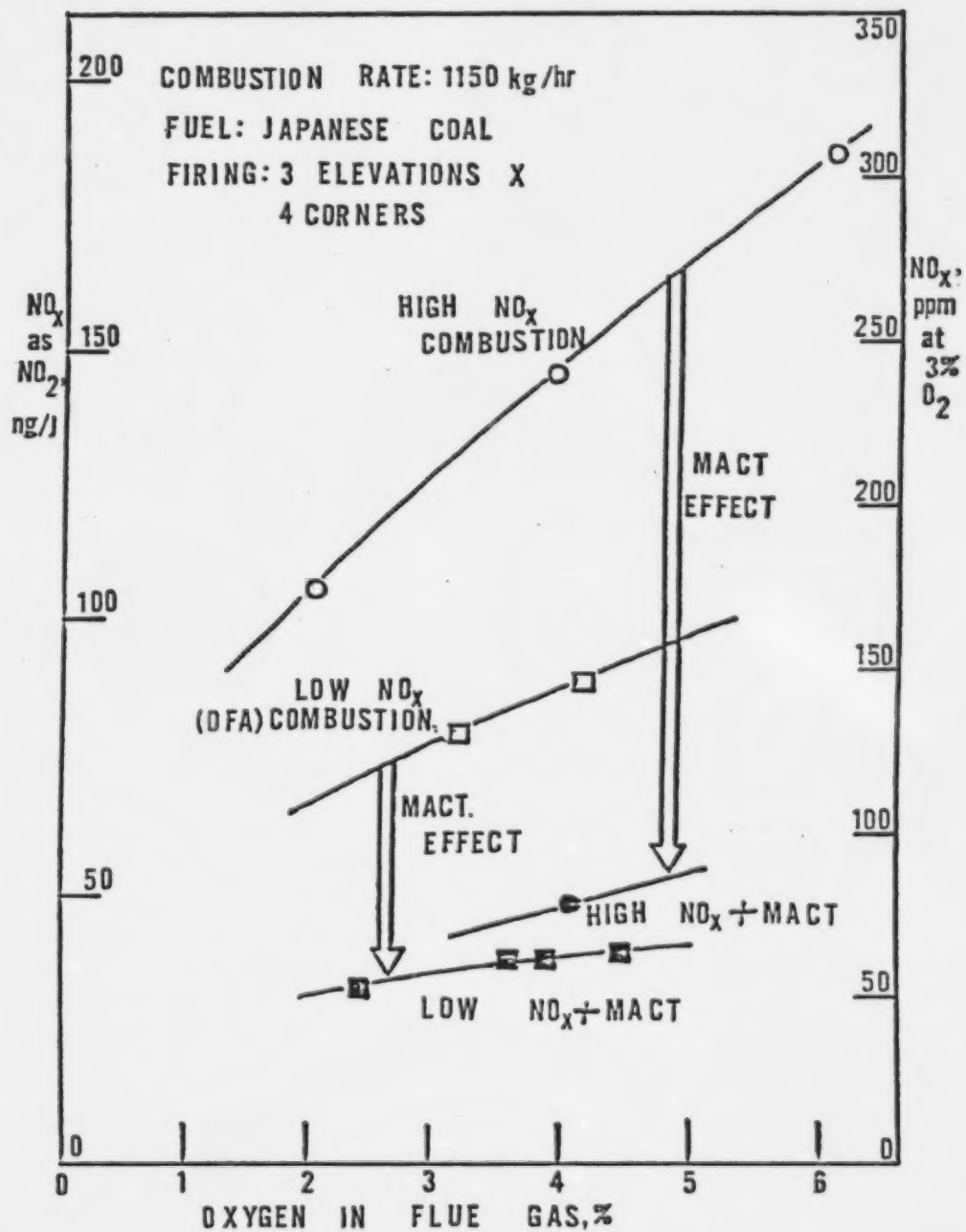


FIGURE 2. NO_x REMOVAL, COAL FIRING (REF. 2)

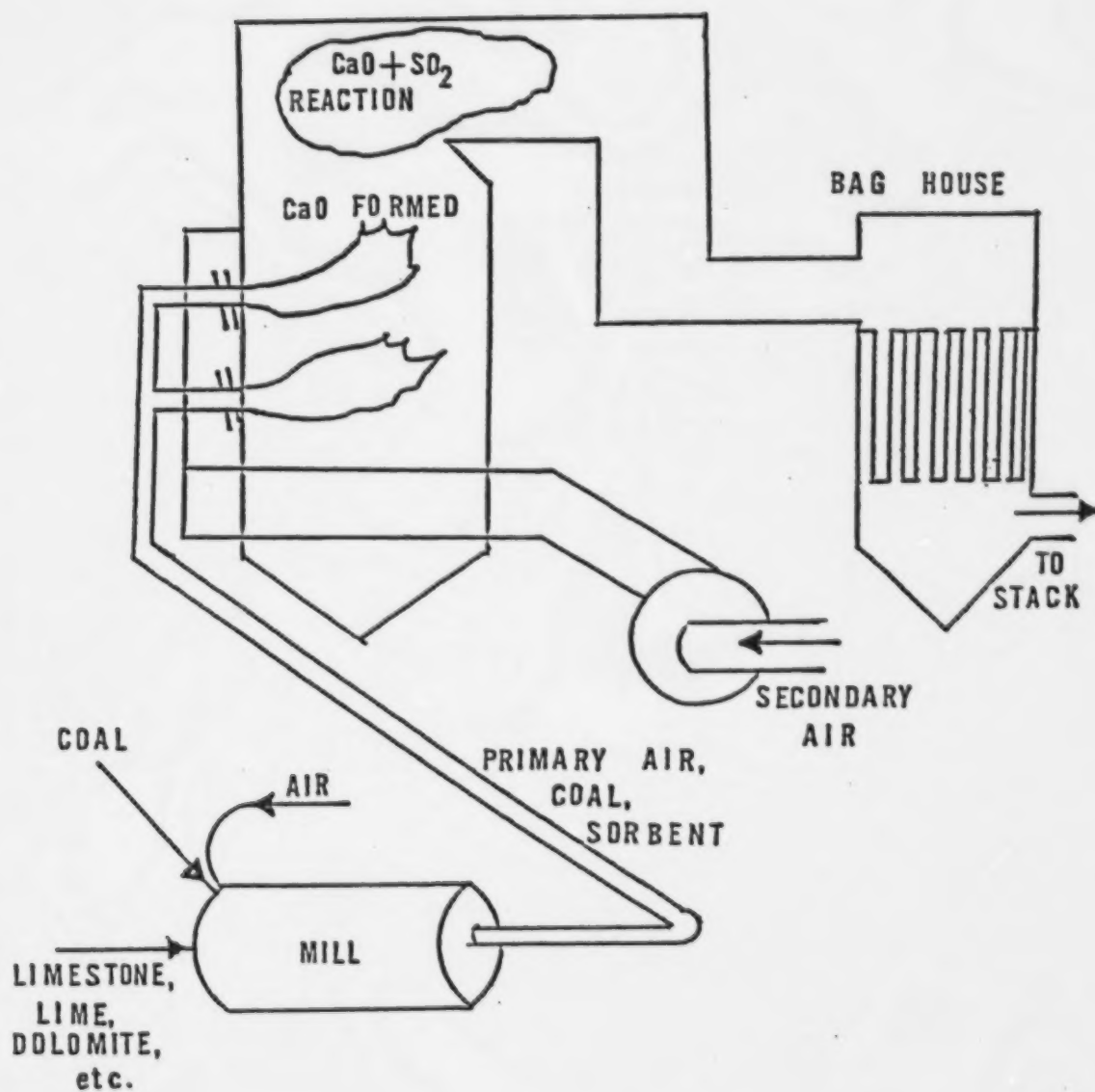


FIGURE 3. SCHEMATIC OF SORBENT INJECTION

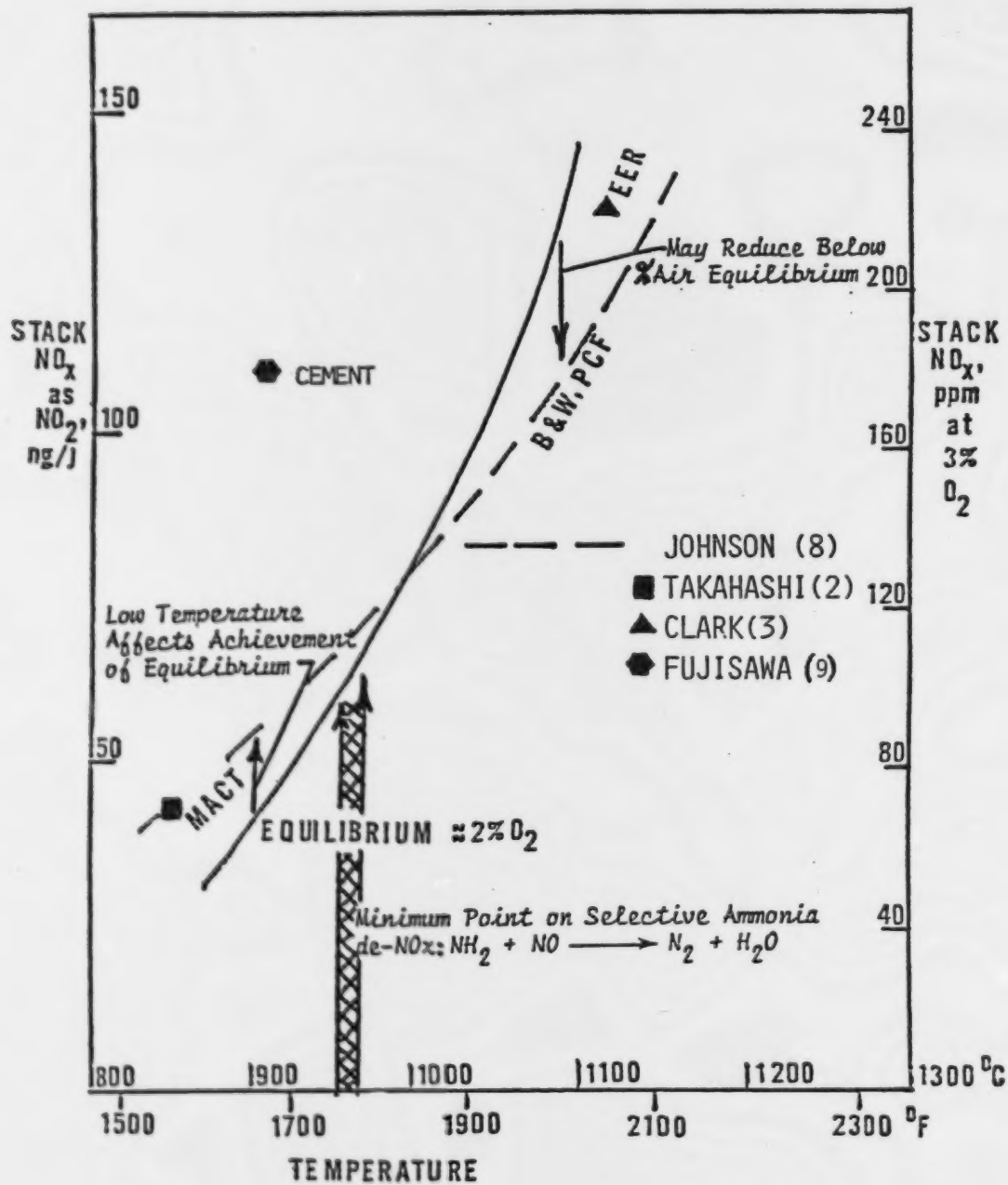


FIGURE 4. RESULTS OF REBURNING IN VARIOUS TYPES OF PROCESSES & EQUILIBRIUM NO LEVELS

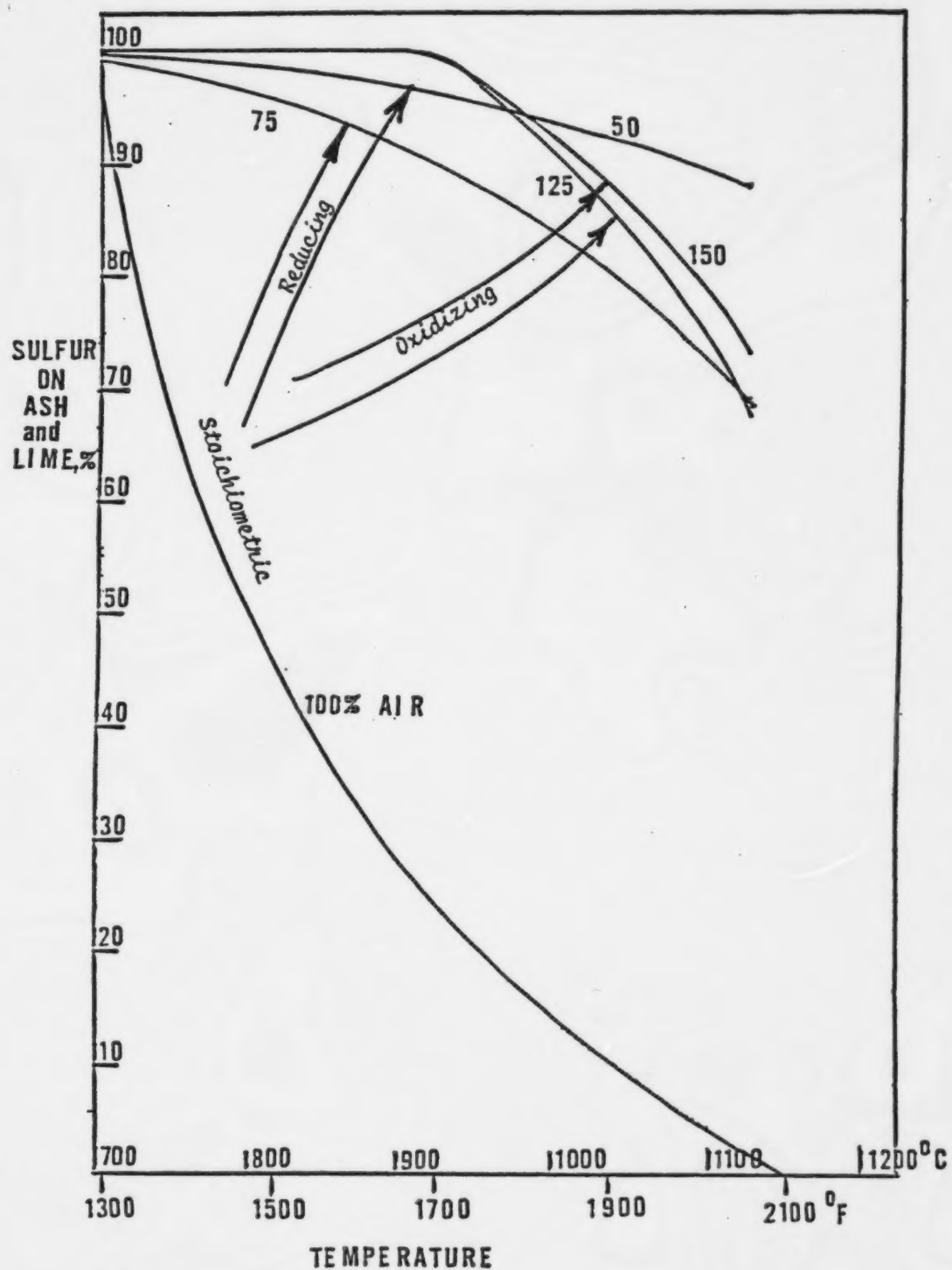
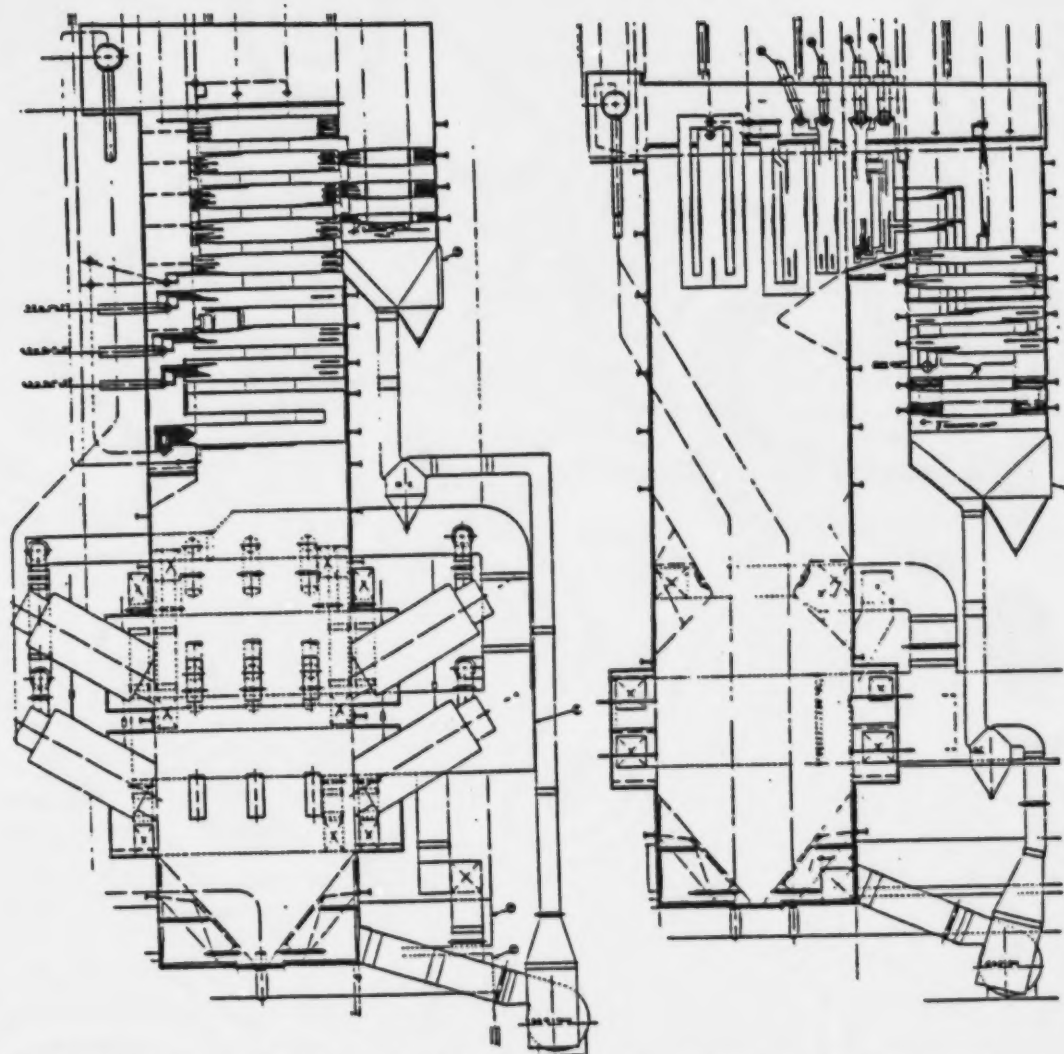


FIGURE 5. EQUILIBRIUM SULFUR RETENTION FOR A LIGNITE WITH ADDED LIME, COAL, 0.98% S, CaO/S 3.1 (REF. 10)



A) PRELIMINARY DESIGN OF PRIMARY
COMBUSTION FURNACE

B) PRIMARY COMBUSTION
VENTURI FURNACE DESIGN

FIGURE 6. PRELIMINARY BABCOCK & WILCOX DESIGNS (REF. 8)
OF PRIMARY COMBUSTION FURNACES

RETROFIT EXISTING BOILERS

- Derate
- Move Burners
- Add Flue Gas Recirculation
- Use Oil/Gas For Final Fuel In Coal-Fired Boilers
- Use Catalytic High Air Burner For Aid Completion
- Install Burners Outside Of Existing Furnace

INSTALL IN NEW FURNACE

- More Energy Extraction In Furnace
- Some Superheat and Reheat In Furnace
- Alternate Burner Configuration
- Flue Gas Recirculation For Upper Fuel Injection

INDUSTRIAL BOILERS OR PROCESS HEATERS FUEL STAGING WITH SINGLE BURNER SYSTEM

- Hitachi Zosen
- John Zink (11)

SUSPENSION PREHEAT CEMENT BURNER WITH REDUCING DENITRIFICATION OF KILN EXHAUST

- Kobe Steel, Ltd.

GLASS FURNACE EXHAUST/REDUCING AFTERBURNER WITH HEAT RECOVERY

IN-FURNACE REDUCTION IN COGENERATION

- Repowering Boiler With Reducing Zone Combustion
- Gas Turbine Followed By a Fired Boiler
- Internal Combustion Engine Followed By A Fired Boiler
- Pollution Exhausts Followed By Reducing Fired Boiler

FIGURE 7. POSSIBLE IMPLEMENTATION FOR IN-FURNACE
NO_x REDUCTION

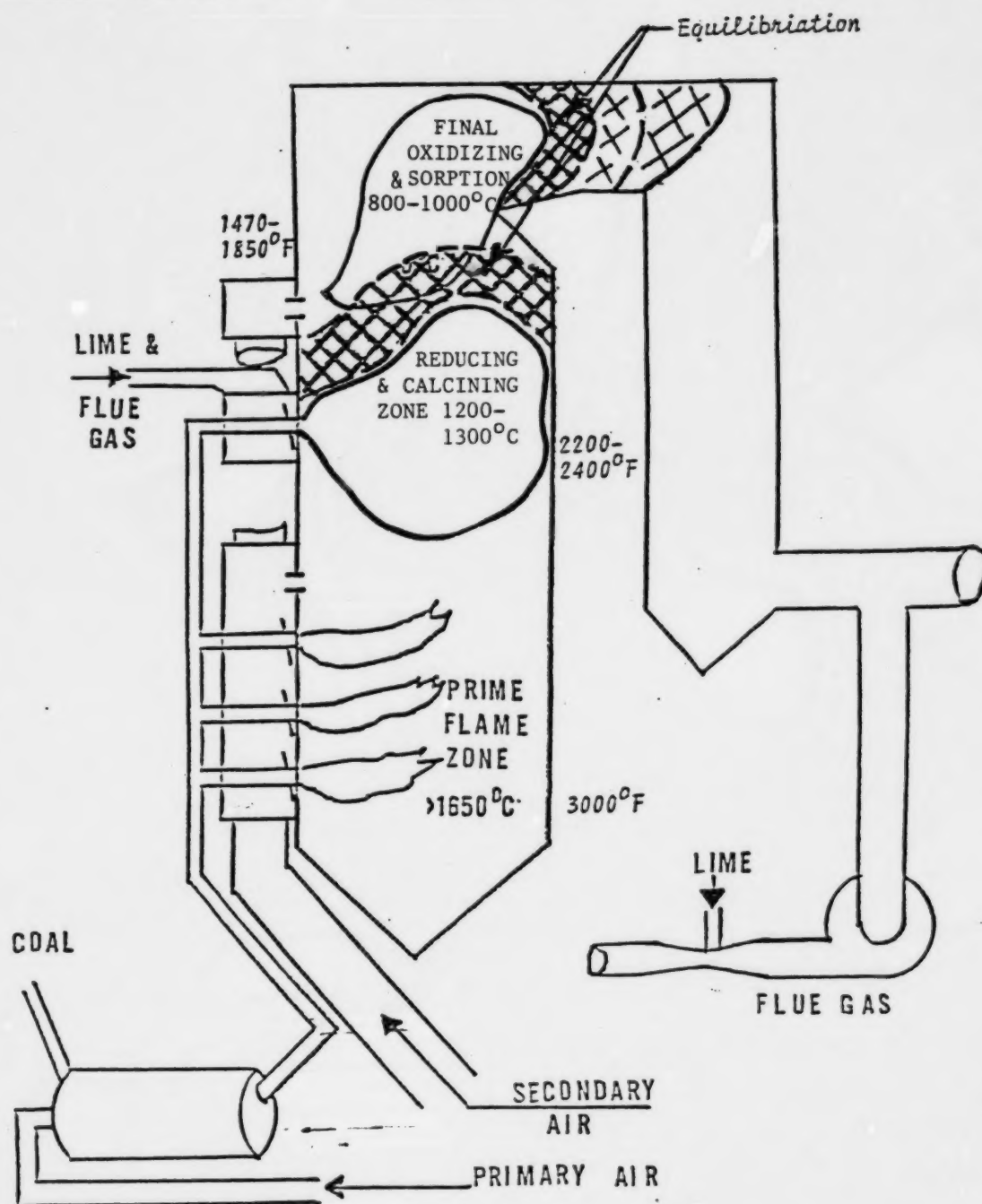


FIGURE 8. IN-FURNACE NO_x REDUCTION WITH SORBENT INJECTION FOR SO_x CONTROL

SESSION VI

FURNACE LIMESTONE INJECTION
Chairman, James H. Abbott
EPA, IERL/RTP

THE DRY ADDITIVE PROCESS FOR THE REDUCTION OF
SO₂ EMISSION IN BROWN COAL FIRED BOILERS

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ABSTRACT

A flue gas desulfurization process using dry calcium-based materials as additives with the fuel has been proposed based on the results of combustion trials with Rhinish brown coals. The applicability of the process was evaluated in a brown coal fired utility boiler (175 ton/hr steam production) over several years. The first results of this project were published in 1978 (1) and 1981 (2). In the meantime, a detailed research program has been carried out in order to reduce the amount of additive necessary to provide a given SO₂ reduction. After an introduction to the problem and the specific fuel properties of Rhinish brown coal, this paper describes results concerning the choice of additives for this process.

INTRODUCTION

The increased public attention associated with air pollutants produced by industrial combustion sources in recent years has resulted in the promulgation of clean air acts in many countries. Industry is responsible for insuring that the discharge of solid and gaseous pollutants in the flue gases is maintained below some minimum concentration when burning fossil fuels. Sulfur oxides have a high priority amongst atmospheric pollutants; therefore, flue gas treatment and to some extent fuel desulfurization processes are the subject of considerable deliberation when planning a new installation (e.g., for electricity production).

Flue gas desulfurization technology has been known for several years and the available processes can be divided into two groups as follows:

- scrubbing processes which remove sulfur oxides from the waste gases;

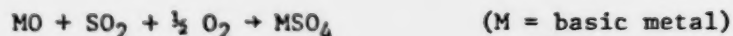
- dry cleaning methods which remove sulfur oxides by the injection of certain additives into the combustion system.

Scrubbing systems have been installed behind oil and bituminous coal fired boilers. Dry cleaning methods were investigated more than a decade ago for coal fired units, but were abandoned mainly because of high flame temperatures and problems associated with mixing the additive and the combustion gases.

Experience gained to date with SO₂ scrubbing systems and bituminous coal fired stations have been generally positive, but these systems cannot be applied to low calorific value fossil fuels like brown coals. This is mainly because the properties of the fuel vary significantly with time, giving large changes in effluent SO₂ concentrations. In addition, the temperature distribution within the boiler is significantly different from bituminous coal fired systems.

PHYSICAL AND CHEMICAL CONSIDERATIONS

During combustion the sulfur content of the fuel is converted primarily to SO₂. The subsequent oxidation to SO₃ is kinetically limited and, therefore, its concentration is small in most cases. For solid fuels with high concentration of basic components, like coals from the Rhinish basin in the Federal Republic of Germany, a high percentage of the SO₂ is retained in the fly ash in the form of solid sulfates. It is believed that a catalytic surface reaction



is responsible for the sulfation process. This "natural retention" is a heterogeneous reaction which is not only dependent upon the local temperature and concentration of the reactants and their products, but also upon the mixing of the species and the available surface area of the solid component. Since the thermodynamic equilibrium conditions are not attained in practical combustion systems, the residence time must also be considered. The sulfation process described above can be used for further SO₂ removal if a basic oxide is added to the fuel or the combustion products. The residence time available in the necessary temperature range for sulfation is limited, and therefore a high specific surface area of the solid additive and optimal mixing of the additive with SO₂ are vital boundary conditions.

BROWN COAL FIRED COMBUSTION SYSTEMS: SPECIFIC PROPERTIES

The brown coal from the Rhinish basin has several important properties which distinguish it from other solid fuels, e.g., bituminous coals. The fuel contains a relatively high moisture content of approximately 55 - 60 percent on a raw coal basis. Not only does this lead to a large flue gas volume, but it also limits the flame temperature to below 1150 C. Figure 1 presents a typical time/temperature profile throughout a brown coal fired

boiler. The relatively long residence times are due to the low heat transfer rates in the radiative part of the combustion system to avoid excessive slag formation. In addition, the flue gas velocities in the convective section are minimized in order to prevent erosion of the tubes by the particulate matter which is suspended in the flue gas.

The ash content of the brown coal, between 4 - 7 percent as an annual average, is comparatively low as is the sulfur content, which averaged over several years is approximately 0.3 percent. In contrast to other solid fuels, large variations in the total ash content and, in particular, its chemical composition can be experienced. The high specific fuel consumption of approximately 1.1 - 1.4 tons/MWh (approximately 3 to 4 times higher than for German bituminous coals) are due to the high fuel moisture content, and, therefore, brown coal cannot be blended sufficiently in order to guarantee a reasonably homogeneous fuel quality. Consequently, utilities burning brown coals are faced with a large and unpredictable variation of fuel properties, including sulfur content. Therefore, the SO₂ concentration in the flue gases also varies significantly, and Figure 2 shows typical SO₂ fluctuations measured over a period of twenty hours expressed as 10 minute average values.

Rhinish brown coals are also distinguished by their relatively high calcium concentration. Average values ranging between .3 and .6 percent with values as high as .8 percent concentration. Although there are strong fluctuations of this property, as with all others, there is a strong "natural retention" of SO₂ by calcium oxide. This retention leads to a considerable reduction in the SO₂ emissions in the absence of any desulfurization process. Figure 3 shows the natural retention for utility boilers given as a monthly average and defined as

$$\epsilon_K = \frac{SO_{2\max} - SO_{2\text{meas}}}{SO_{2\max}}$$

with

$SO_{2\max}$ = Theoretical maximum SO₂ concentration, if all sulfur in the fuel were converted.

$SO_{2\text{meas}}$ = Actual SO₂ concentration measured at the end of the combustion system.

It can be seen that the natural retention is very erratic, but that values in excess of 50 percent may be attained. It can also be seen that the retention is dependent on fuel properties, such as calcium and sulfur concentration, and the wide scatter is believed to be due to other parameters which are mainly related to the combustion process.

The net result of the low, but fluctuating, sulfur content of the coal and the high, but also variable, natural retention is a wide variation in SO₂ emissions. Figure 4 shows typical SO₂ emission values given as

shift averages. Similar tendencies are found for all four boilers because the fuel fired over the period of investigation was almost the same. However, it is obvious that the different combustion systems may result in very different absolute values of SO_2 concentration in the stack gases. This indicates the high sensitivity of the calcium based natural SO_2 retention to the time/temperature history in the combustion system, which in turn explains the scatter of the points shown in Figure 3.

RESULTS AND DISCUSSION

The natural retention can be enforced by increasing the calcium content of the fuel artificially in order to further reduce SO_2 concentrations in the flue gases in order to meet limiting emission values in compliance with existing or expected regulations. It was shown previously (1, 2) that calcium based additives mixed with the brown coal prior to the combustion system will react similarly to the calcium content of the coal and reduce SO_2 emissions. These findings are summarized in Figure 5, which shows the reaction and qualitatively its dependence upon the main combustion parameters and additive properties. Eventually, an optimal temperature range with regard to calcium sulfate formation and, hence, the desulfurization of the flue gases can be found somewhere between 600 - 1000 C. In particular, if, for example, $\text{Ca}(\text{OH})_2$ or CaCO_3 is used, the fast calcination which occurs in the flame root will help to improve the reactivity of the additive towards SO_2 capture by exposing an enlarged specific surface area to the SO_2 containing flue gases.

Based on this principle, a utility boiler with a capacity of 60 MWe was equipped with an additive feed and distribution system in order to investigate the dry additive process (DAP) under operating conditions. The test results from this installation were very promising, leading to the construction of a full scale demonstration at a 300 MWe boiler. At this site, operation is scheduled to commence in January 1983 and a one to two year test program is proposed, which will investigate all the effects of DAP on boiler performance, particularly operation, maintenance, efficiency, and availability.

Both the large scale DAP projects follow the general scheme which is shown in Figure 6. The additive is delivered to the site by road or rail transport and is fed by storage bunkers and distribution vessels, such as screw feeders or similar conveying systems, to the coal feeder which supplies the coal to the mill. Both coal and additive are intimately mixed when they pass through the mill and they are then transported together to the burner. The calcination of the additive resulting in free lime and the subsequent calcium sulfate formation takes place within the boiler. The product, together with the fly ash, is finally removed from the flue gases by an electrostatic precipitator.

Although the DAP was found to be simple and effective, especially with fuels with strongly variable composition, several disadvantages cannot be neglected. A high and reactive specific surface area of the calcined additive is required in order to reduce excessive amounts of additives

because of the heterogeneous nature of the desulfurization reaction. Additive requirements must be minimized, because not only do the costs of the DAP process depend upon additive requirements because of supply, transport and storage. The additive also increases the dust load in the combustion chamber. This may lead to changes in heat transfer, fouling and slagging of the heat transfer surfaces and a degradation in electrostatic precipitator performance.

In addition, the relatively short residence time in a utility boiler prevents complete utilization of the available calcium. Thus, a severalfold stoichiometry of calcium with regard to sulfur is necessary, which also increases the amount of additive required for a given SO_2 reduction.

For these reasons, RWE is engaged in an intensive research program in order to optimize the DAP by minimizing the required additive/sulfur ratio. To date, the choice of the additive, i.e., its type, origin, preparation and pretreatment, have been found to be significant parameters in the formation of calcium sulfate. Investigations were carried out in the RWE test facility which is described in detail elsewhere (3) with typical brown coal flames, and some of the major results of these investigations are described below.

The sulfation process is dependent upon the size of the additive. Figure 7 shows that carbonates will react differently when ground to different fineness. The finer the particles, the higher the SO_2 removal from the flue gas. For hydroxides (see Figure 8), similar results were observed. However, the absolute values of sulfur reduction are superior to those attained with carbonates. Also, the calcination of the CaO prior to slaking during the hydroxide process has a pronounced effect upon SO_2 retention by $\text{Ca}(\text{OH})_2$ (see Figure 9). The softly calcined CaO results in a very reactive hydroxide, while with the so-called hard calcination, poor reactivities were observed. With dolomites (see Figure 10) the SO_2 removal improves with increasing percentage of MgCO_3 in the additive material.

These results suggest that there is a potential for optimizing the DAP by an appropriate choice of additive because the calcium utilizations can vary widely. However, for practical purposes, the calcium utilization may not be the controlling factor. The additive fuel ratio and the cost of the additive are of interest for operational and economic optimization. Figure 11 compares several additives expressed as a percentage of the coal. For almost identical combustion conditions, the SO_2 retention varies strongly from hydroxide as the best case via hydrated calcined dolomite, finely ground carbonate, dolomite, down to a carbonate of average particle size (10 percent $> 90 \mu\text{m}$) which represents the worst case. Such results are the necessary basis for further economic considerations.

The results show, in general, a reasonably high additive utilization. This may differ in other combustion systems, for example, when the same additives are applied to boilers. Scaling factors, which have not yet been defined, may have to be considered. This topic will be the task of future comparative trials on the RWE test rig, 60 MWe and 300MWe scales. Even if there are differences in the absolute retention values at different scales, one would expect the relative reactivities of the additives to be similar or almost equal to the ratios given by the combustion rig results.

It should be mentioned that combustion conditions, hence the time/temperature history of the additives in the combustion system, are expected to be another important variable with regard to additive utilization. Consequently, variations due to boiler design or operational parameters, which affect the temperature field, will result in a variation in the SO₂ retention. Detailed insight into these parameters is the major goal of further investigations which are scheduled starting November 1982 through February 1983.

In summary, it can be stated that the dry additive process (DAP) is a simple and effective method of reducing SO₂ emissions for fuels with low flame temperatures, in particular for cases with strongly varying fuel properties. The disadvantages, such as high additive consumption, can be compensated for by an appropriate choice of the additive material. Further investigations are being carried out at present in order to improve the knowledge of additive properties and their dependence on combustion conditions.

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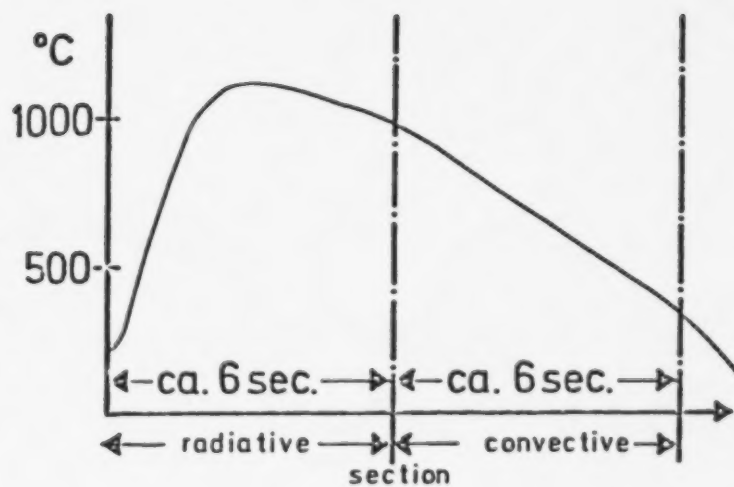


Figure 1: Time/temperature history in a brown coal fired utility boiler (schematic)

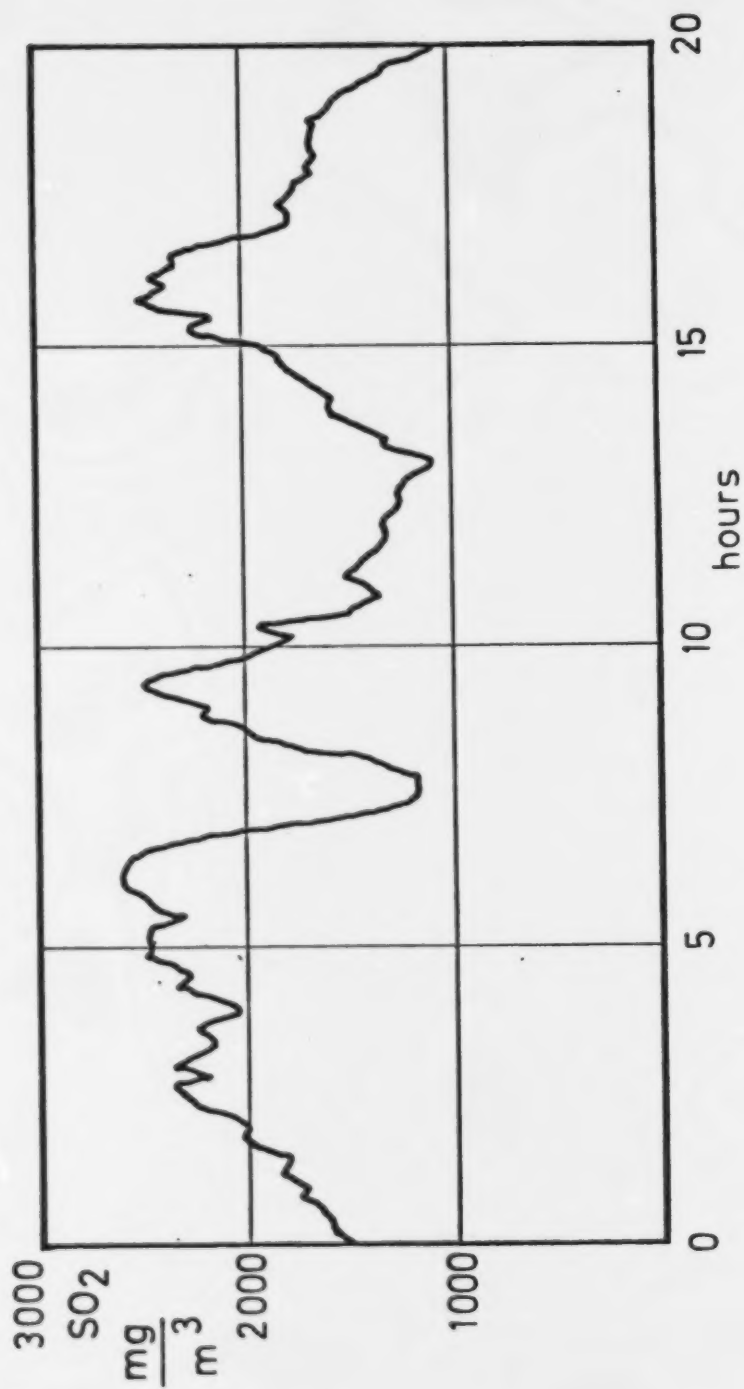
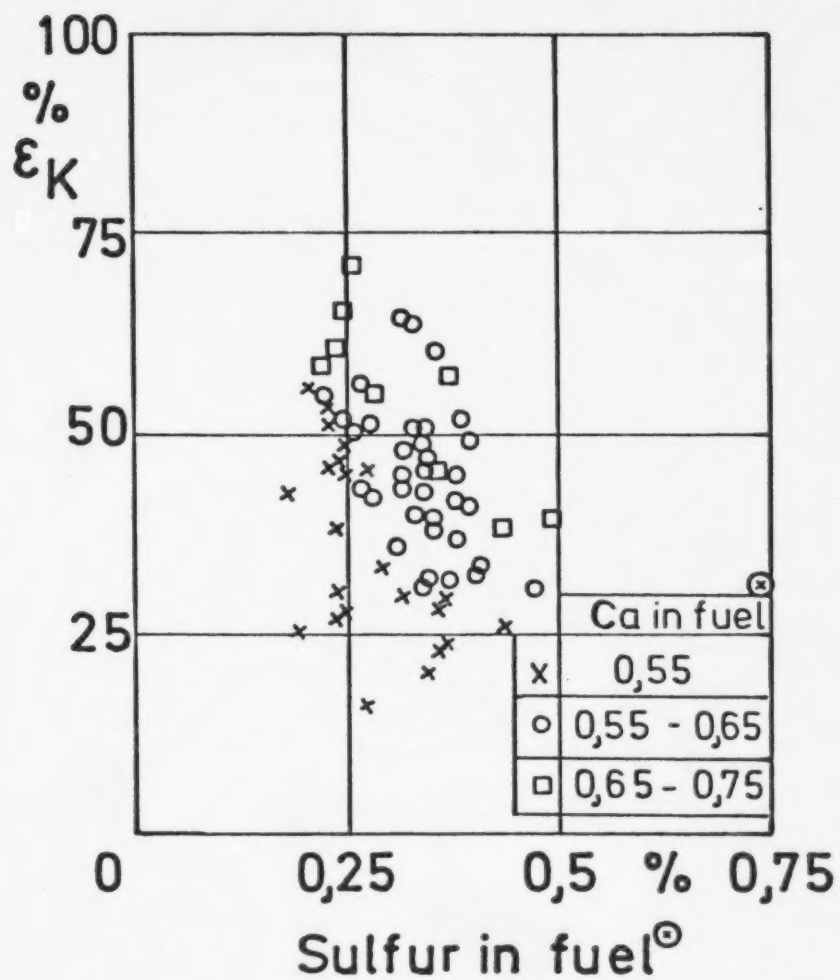


Figure 2: Variation of SO₂-emission,
10 minute average values (example)



⊙ on as-received basis

Figure 3: Natural SO_2 -retention;
monthly averages for boiler fuels

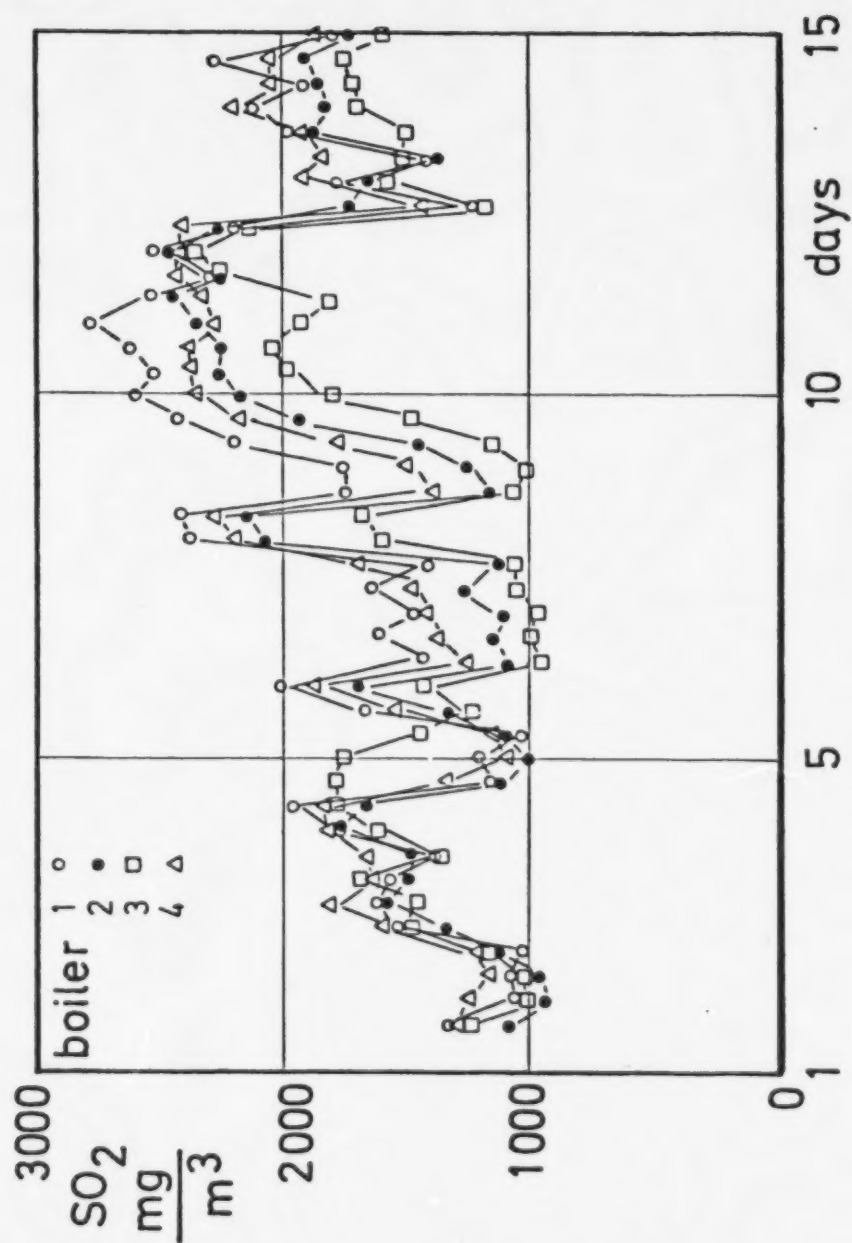


Figure 4: SO₂-emission for different boilers,
shift average values (example)

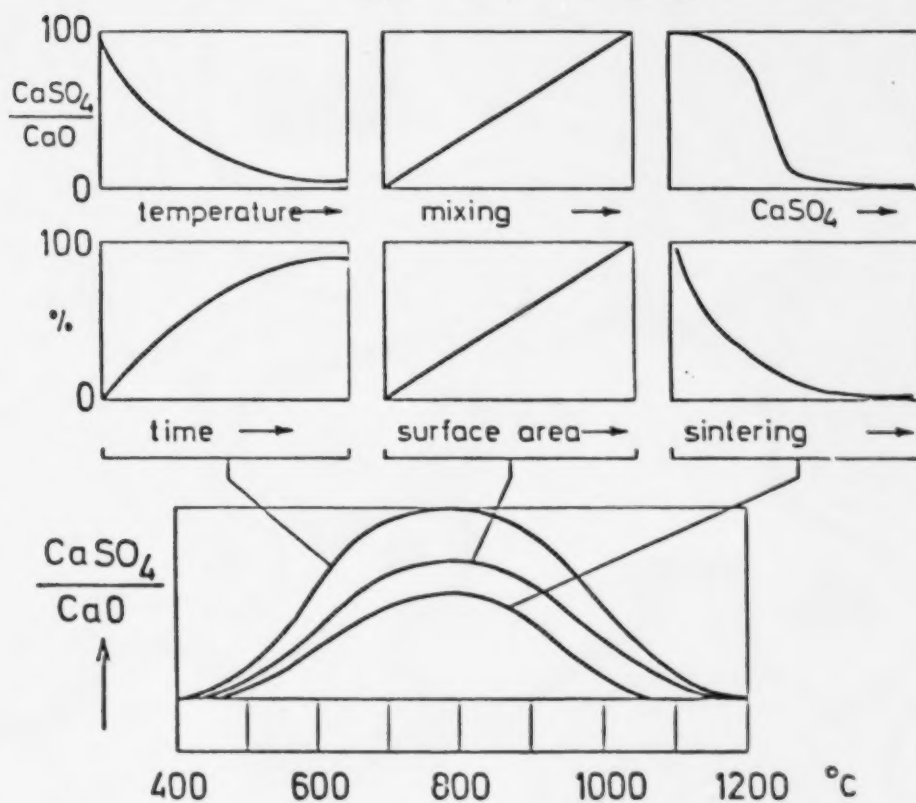
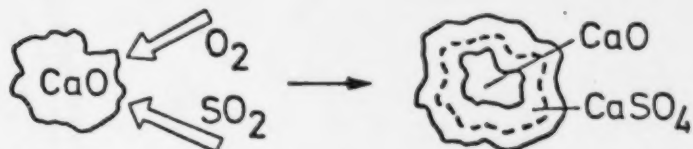
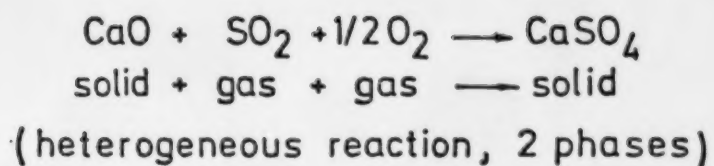


Figure 5: Sulfate reaction dependencies
(schematic)

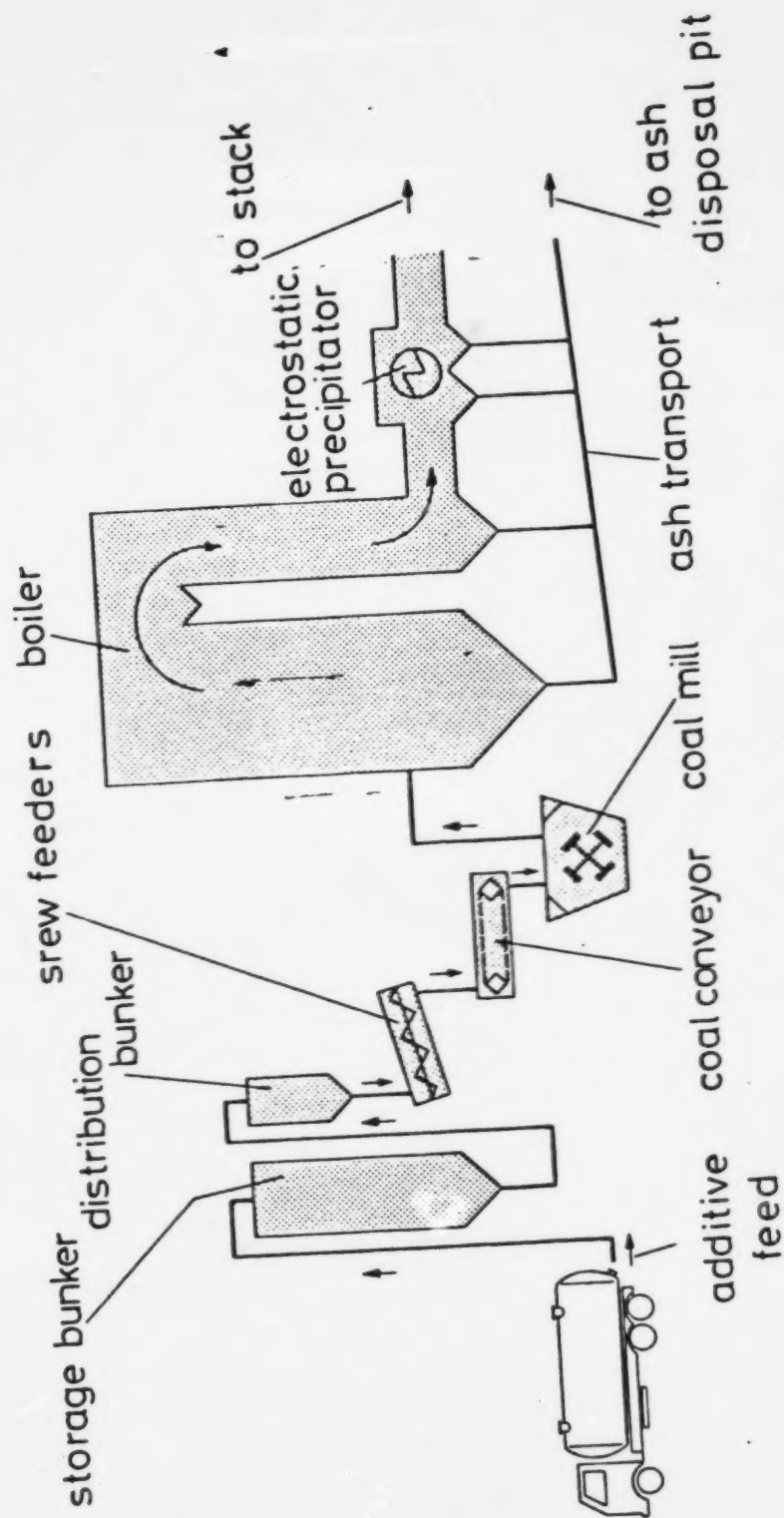


Figure 6: RWE dry-additive-process (schematic)

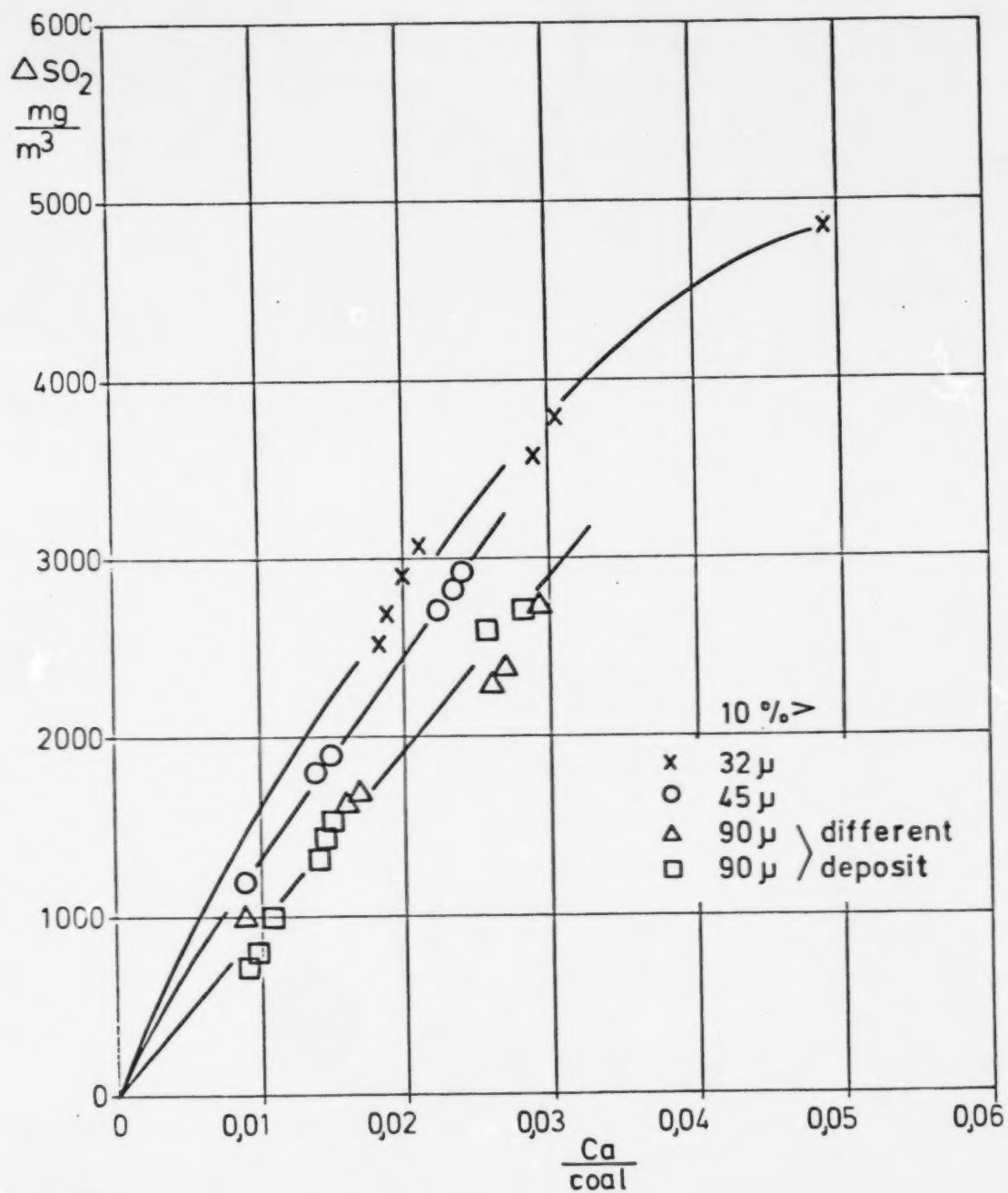


Figure 7: SO_2 -removal; carbonates

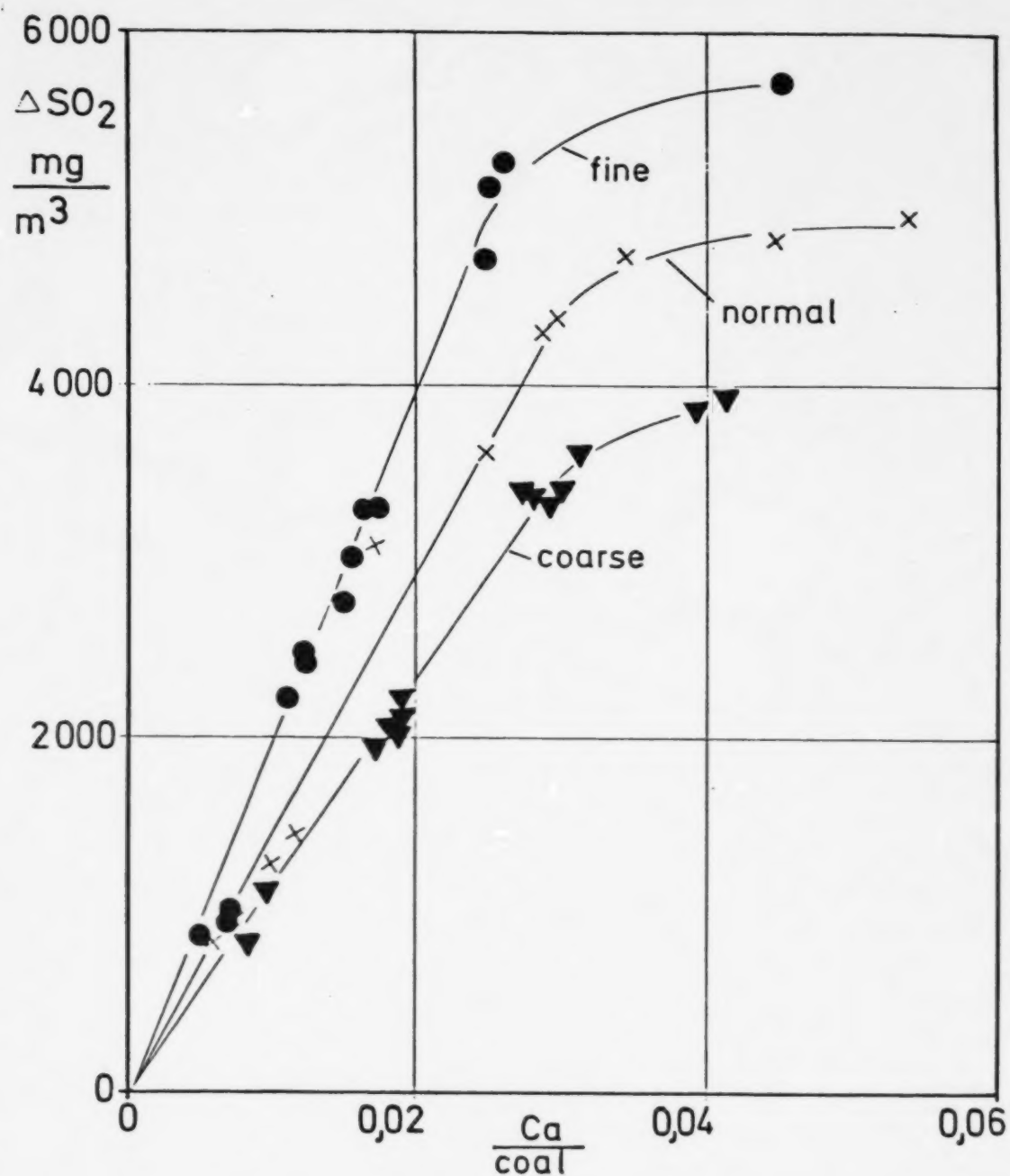


Figure 8: SO_2 -removal; hydroxides

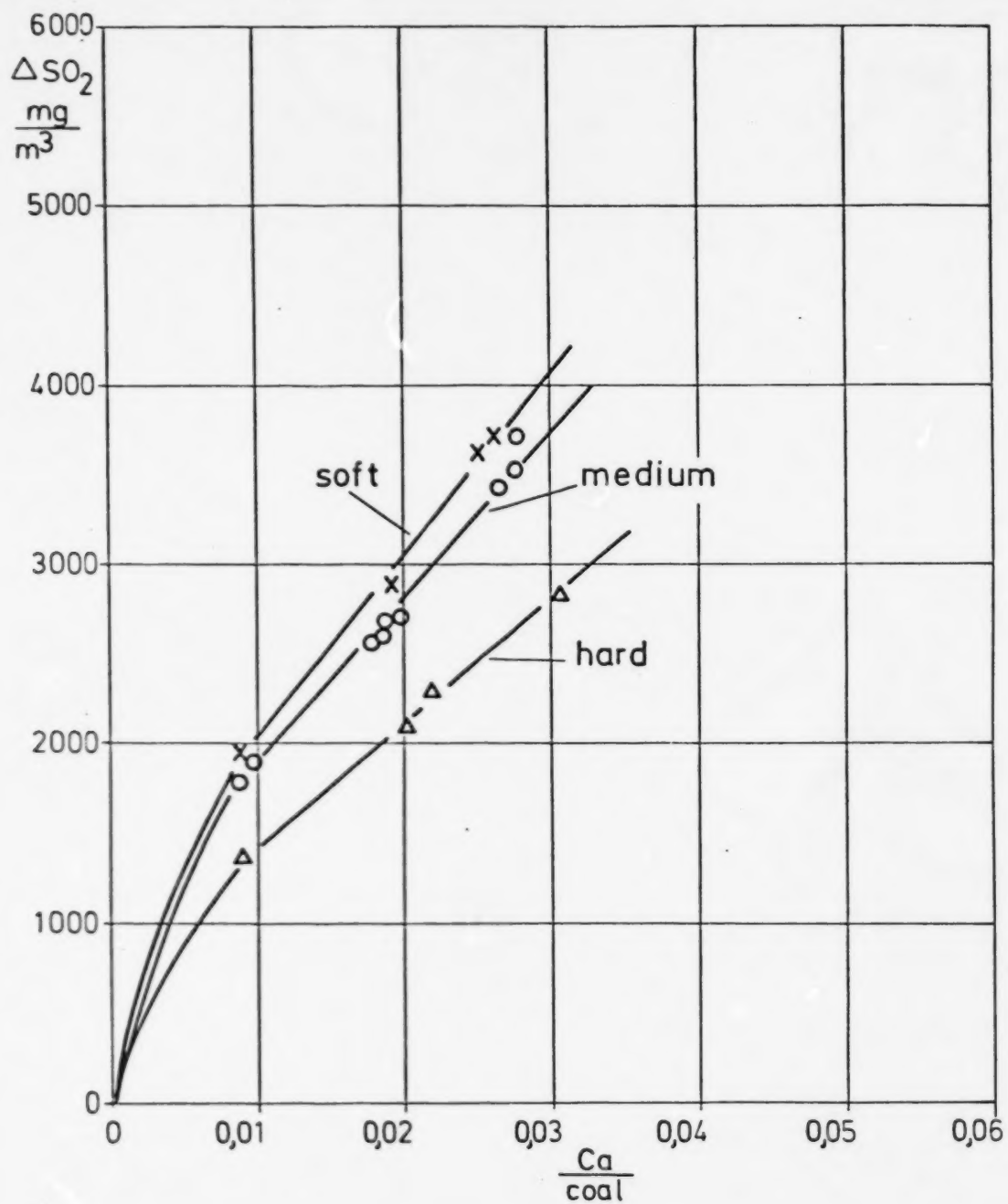


Figure 9: SO₂-removal; hydroxides
influence of pretreatment

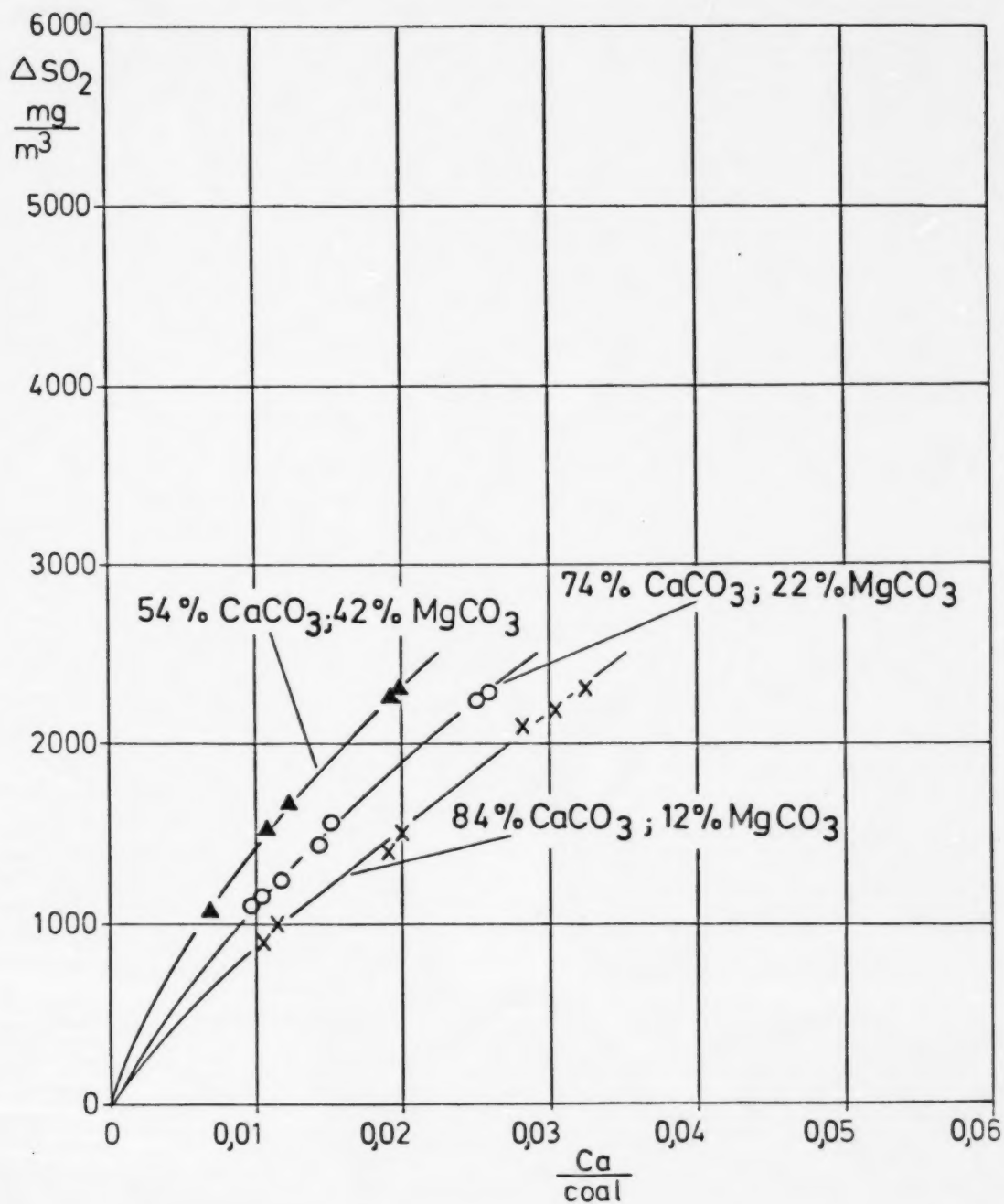


Figure 10: SO_2 -removal; dolomites

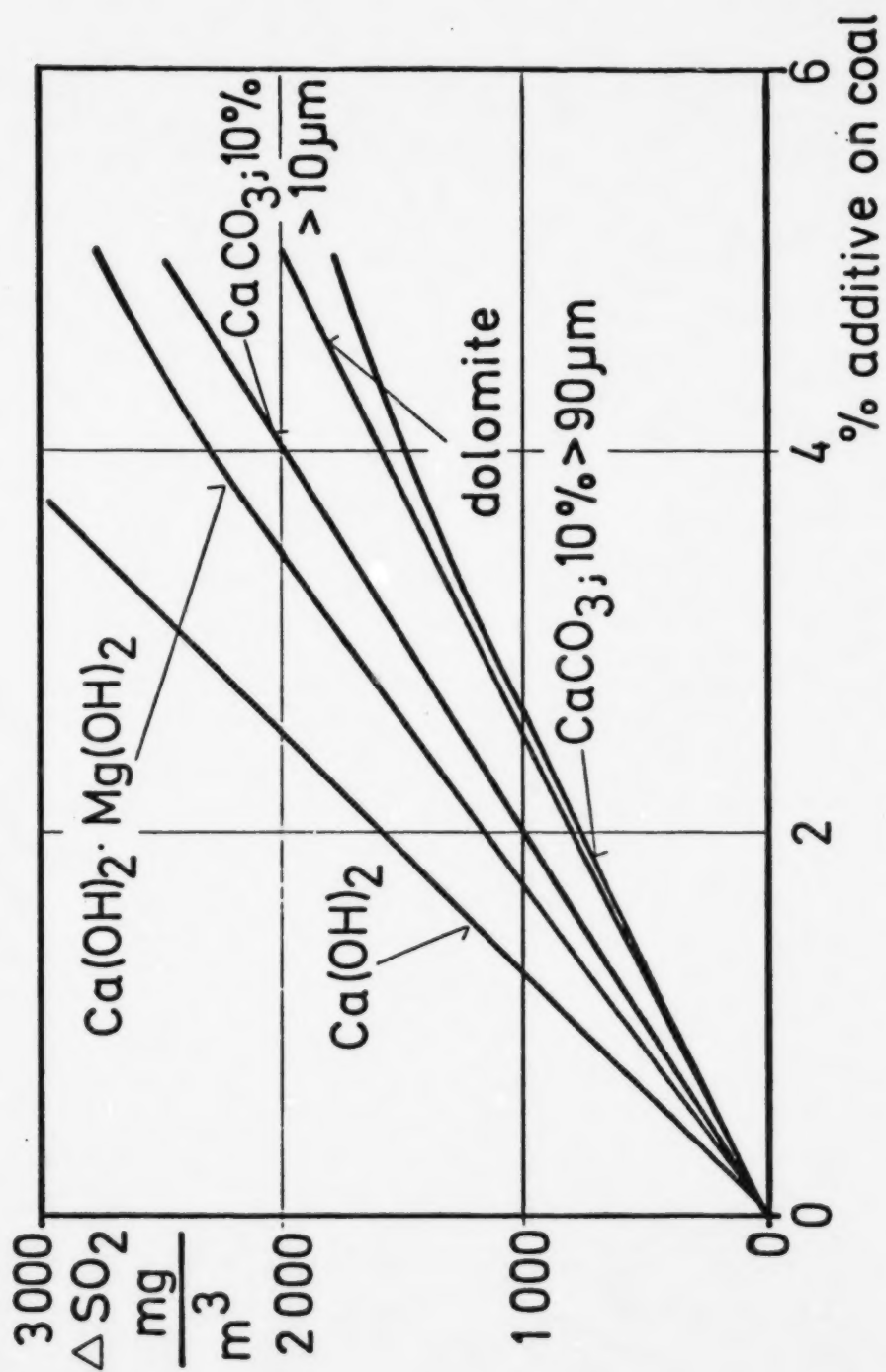


Figure 11: SO_2 -removal; comparison of additives

OPERATION AND PERFORMANCE REPORT OF
THE STEINMÜLLER LOW NO_x SM-BURNER
AND ITS POTENTIAL TOWARDS UTILITY BOILER
SO_x-CONTROL VIA SORBENT INJECTION

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ABSTRACT

Following the successful pilot plant tests the combustion equipment of a 700 MW coal fired power station was changed to staged mixing burners (SM-burners). Both, to ease the retrofit and to safely allow the execution of a measuring program as retrofit burners a modified version of the experimentally optimized SM-burner design was used for the boiler.

In spite of the narrower operational limits of the modified SM-burner the envisaged goal of a 50 % NO_x reduction was met in the boiler demonstration tests. Furthermore a burner load dependent automatic secondary/tertiary air flow control system developed to guarantee a safe burner operation at low NO_x levels over a wide turn down ratio, was introduced successfully.

In the past 42 months of operation neither short term nor long term performance problems due to low NO_x operation could be detected.

Earlier successful experiments with Calcium-based sorbent addition to lignite for SO_2 absorption during combustion initiated a further development step for the SM-burner concept towards its application for an in situ desulfurisation process.

A prototype "de NO_x -de SO_x " SM-burner has been successfully tested on a pilot scale at the International Flame Research Foundation with high calorific value fuels as coal, heavy fuel oil and natural gas. Presently a demonstration program is under way to define the potential problem areas to be taken account of in the process application for coal fired steam generators.

The paper comprises a status report on both combustion modification technologies as well as further plans for full scale demonstration and commercialization.

1 INTRODUCTION

Both federal and local government regulations on NO_x - and SO_x -emissions for power station boilers in Germany force utilities and boiler manufacturers to develop techniques which allow the operation of boilers in compliance with present and future regulations.

It has been shown by various international R&D programs that the most cost effective method to meet the NO_x provision lies in the reduction of NO_x -formation by optimizing the combustion process, respectively the combustion equipment.

Numerous experiments have clearly indicated that it has to be differentiated between basically two NO_x -formation mechanisms,

- the 'thermal NO_x ' route, comprising all reactions which in their final result lead to the oxidation of originally molecular nitrogen, and
- the 'fuel NO_x ' route, describing the oxidation of fuel bound nitrogen.

It is now well established that the thermal NO_x -formation predominantly depends upon the reaction temperature and the prevailing residence time at high temperatures, whereas the fuel NO_x -formation is more dependent on the oxygen concentration in the pyrolysis zone of the flame.

The relative importance of these individual reaction routes on the overall NO_x -formation varies with the nitrogen content of the fuel. With natural gas firing due to the absence of fuel bound nitrogen only thermal NO_x can be formed, and thus the emission be minimized by controlling the time temperature history of the combustion products.

At residual fuel oil and pulverized coal firing the fuel NO_x -formation mechanism often plays the dominant role. Experiments by Pershing et al (ref. 1) have shown that up to 80 % of the overall NO_x -emission at coal firing was contributed by the fuel NO_x -formation mechanism.

As coal is or soon will be the only important fossil fuel for power generation in Germany it is evident that controlling NO_x -emission from power stations will only be possible when the fuel NO_x -formation mechanism can be controlled.

As stated above, this calls for an oxygen concentration control in the pyrolysis zone of the flame, which at the simultaneous requirement of short intense flames can be achieved by a staged respectively distributed mixing burner concept.

Using the Steinmüller circular burner configuration as basis, a novel staged mixing prototype burner (SM-burner) was designed which was subsequently further optimized and demonstrated in a two-phase program on the demonstration phase of which is reported in this paper. A pilot test and optimization program with a 2.5 MW test burner was followed up by a large-scale demonstration at a 700 MWe power station which is equipped with 24 retrofit SM-burners.

This program was carried out in cooperation with and financial assistance of the German Federal Ministry of Research and Development (Bundesministerium für Forschung und Technologie, BMFT).

A further development step - the application of the SM-burner concept for an in situ desulfurization process via sorbent addition at higher calorific value fuel combustion such as pulverized coal and oil is presently on its way. This program will be sponsored by the Umweltbundesamt (German Environmental Protection Agency).

This latter investigation is aiming towards the use of the well-known high temperature reactions between CaO , SO_2 and O_2 (800°C - 1200°C) which lead to the formation of CaSO_4 as a reaction product.

Earlier successful experiments by Hein with sorbent addition to lignite (ref. 2) as well as the successful capture of SO_2 in fluidized bed combustion with limestone addition to the fuel have indicated that high temperature in situ desulfurization is possible via this route. Measurements by Goldschmidt (ref. 3) exhibited when the lime was added to higher calorific value fuels that not only the operational difficulties due to slagging occurred but also the sulfur capture was relatively poor.

Using the SM-burner concept together with a circumferential sorbent addition technique gave reason to the hope that these measures will allow an effective control of conditions which influence the CaO-SO_2 reaction scheme even with higher calorific value fuels.

The preliminary development step - pilot scale tests - has been taken successfully (ref. 4, 5 and 6). Technology demonstration at large scale is presently on its way.

2

THE SM-BURNER CONCEPT

Fig. 1 shows a SM-burner schematic revealing its deviation from the reliable circular swirl burner. The pulverised coal is fed to the burner throat by an annular fuel gun and injected concentrically to the burner axis.

The former secondary air is now split up into two streams, a reduced secondary air flow which is passed as usual through the annular air duct surrounding the fuel gun, and a tertiary air flow to four tertiary air nozzles which are placed concentrically about the burner swirl exit.

At 100 % coal firing the core air butterfly valve is almost closed. It is adjusted in such a way that just sufficient core air is passed through the central duct to avoid recirculation flows induced by the swirling secondary air into the core air duct.

A variable swirl device allows a control of the secondary air swirl intensity.

The tertiary air quantity, respectively the tertiary/secondary air ratio, can be controlled by the butterfly valve in the tertiary air duct.

To control the overall burner stoichiometry, the total air flow to each burner is measured individually by a ventury type flow meter.

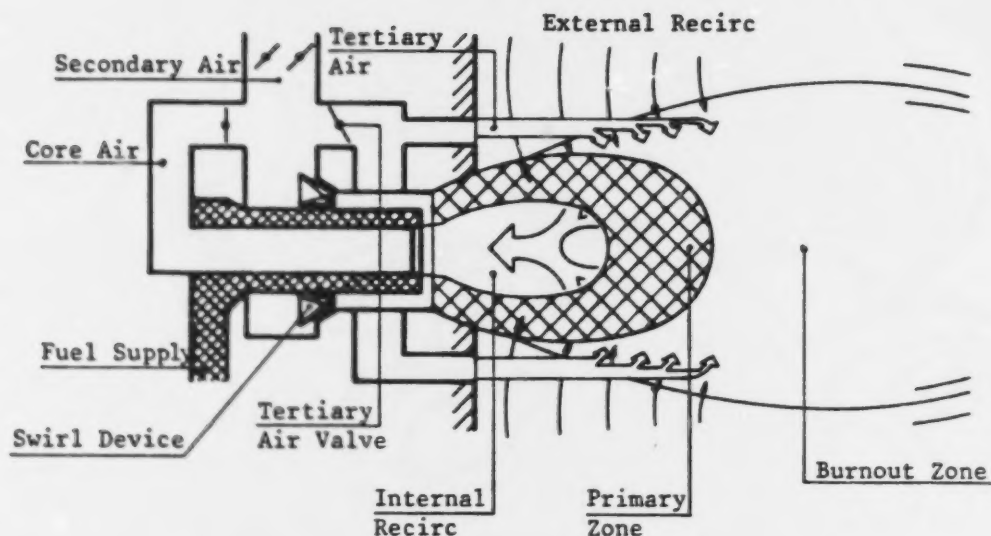


FIG. 1 SM-BURNER SCHEMATIC WITH ANTICIPATED FLOW AND MIXING REGIME.

As a result of the air supply chosen, the flame, which is stabilized within the burner mouth due to the prevailing aerodynamic conditions, is characterized by two distinct zones of different stoichiometry, a fuel-rich primary zone at the burner exit, followed by an overstoichiometric secondary or burnout zone. The design concept thus enables to fulfill the low fuel NO_x -formation requirement of low oxygen concentration in the fuel pyrolysis zone of the flame and additionally, but to a lesser degree, reduces the thermal NO_x -formation as a consequence of lowering the maximum flame temperatures due to interstage cooling and increase of recirculation matter entrainment. Furthermore it enables the addition of sorbents for sulfur capture in such a way that highest temperature zones are avoided and yet the required intense mixing with the combustion products is ensured.

As described in more detail in (ref. 7) a burner configuration could be derived from the pilot plant results for the 2.5 MW prototype burner which yielded the anticipated flow pattern for a wide range of input conditions. At an overall burner stoichiometry of $n = 1.25$ a stable type II flame flow pattern was achieved at full load down to $n_p = 0.55$, n_p being defined as the stoichiometry of the primary zone (Fig. 1).

To ensure the stable flame pattern (Fig. 1) even at load reduction an automatic load-dependent secondary/tertiary air distribution control procedure has been developed for the SM-burner, which was first tested during the demonstration of the 24 retrofit SM-burners at the 700 MWe Weiher power station.

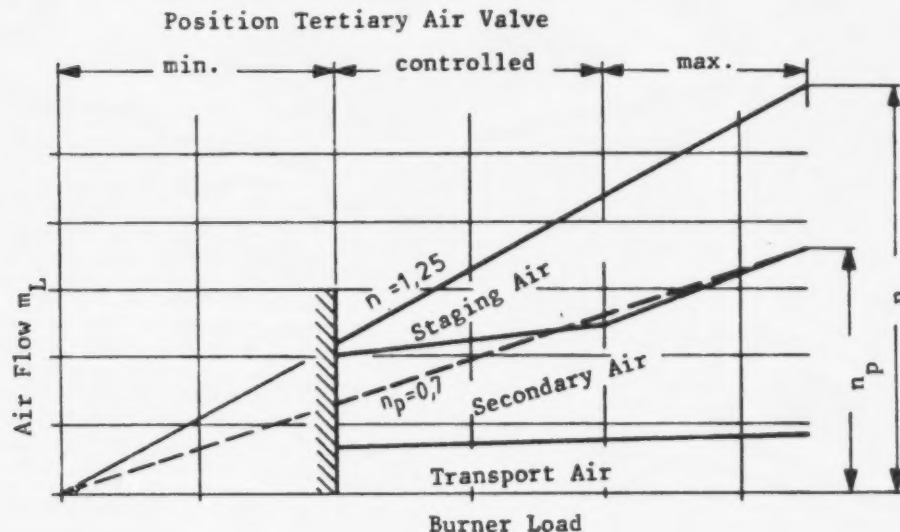


FIG.2 AIR FLOW DISTRIBUTION AS FUNCTION OF BURNER LOAD (CONTROL PROCEDURE).

The load-dependent air flow control procedure is graphically illustrated on Fig. 2. Whereas the total air ($n = 1.25$) is reduced linearly with load, the secondary air flow follows the total air reduction only up to a certain load limit. At a further load decrease the secondary air flow is only degressively reduced which, of course, can be verified only at the expense of the tertiary air flow. As a consequence thereof n_p is increased at reduced load in order to safely maintain the desired combustion characteristics at low load and yet to enable a maximum obtainable NO_x reduction at full load where the prevailing conditions allow safe operation at lower staging ratios.

PARAMETRIC STUDIES ON DE NO_x AND OPERATIONAL EXPERIENCE (700 MWe BOILER).

The single burner pilot plant tests at International Flame Research Foundation (IFRF) (ref. 7) had clearly indicated that at the conditions investigated the by far strongest individual effect on NO_x emission was caused by the stoichiometry of the primary zone n_p .

A series of investigations was carried out at the 700 MWe unit, however only the most important observations will be commented here. A more detailed report has been given in (ref. 8).

In spite of the limited staging air ratio in the retrofit burners this variable proved to be again the by far most effective individual parameter. Fig. 3 shows the strong dependency of flue gas emission levels on the staging ratio. The overall excess air level characterized by the various symbols on Fig. 6 has only a negligible influence.

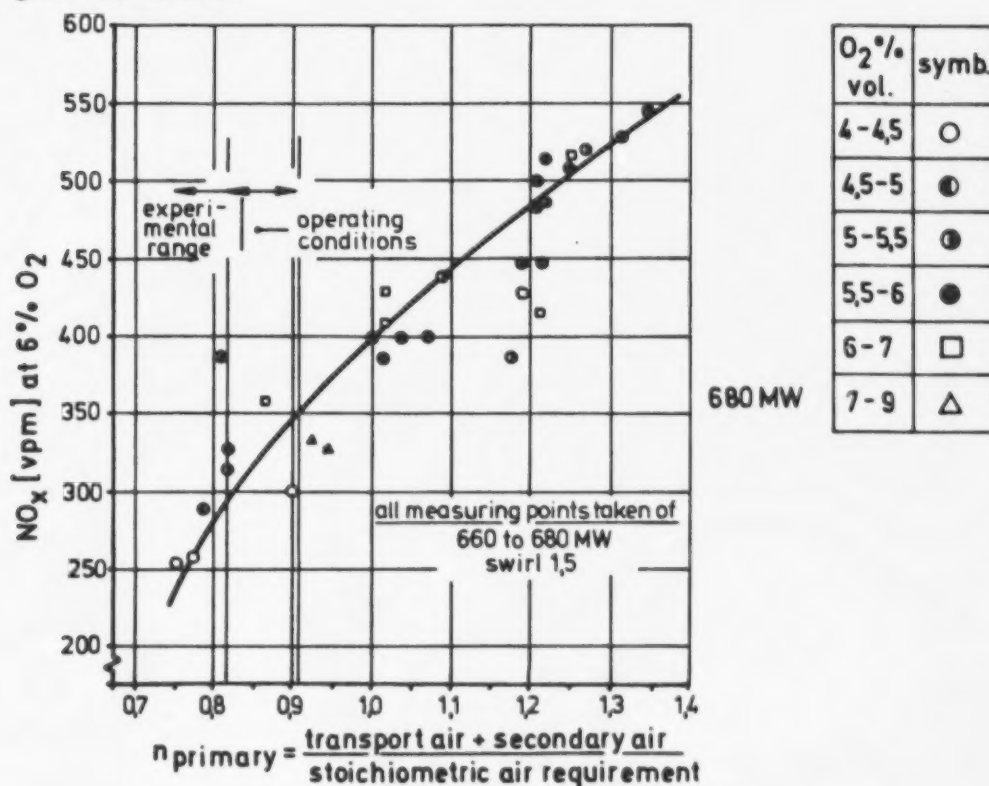


FIG. 3 RETROFIT BURNER, NO_x EMISSION AS FUNCTION OF PRIMARY ZONE STOICHIOMETRY (n_p).

Measurements within the radiant chamber of the boiler have been carried out to identify any significant changes due to the staged mixing operation.

Neither visual observations nor temperature and CO contours (ref. 8) did reveal any detrimental effects even at maximum staging ratios.

The wall thickness measurements before the retrofit action and after 36 months low NO_x operation did not exhibit any increase in corrosion rate.

Flue gas measurements of other pollutants than NO_x did not show any influence of the staged mixing operation on their emission level.

Some initial concern was caused by an initial moderate but distinct increase in the amount of uncombusted carbonaceous matter (Fig. 4).

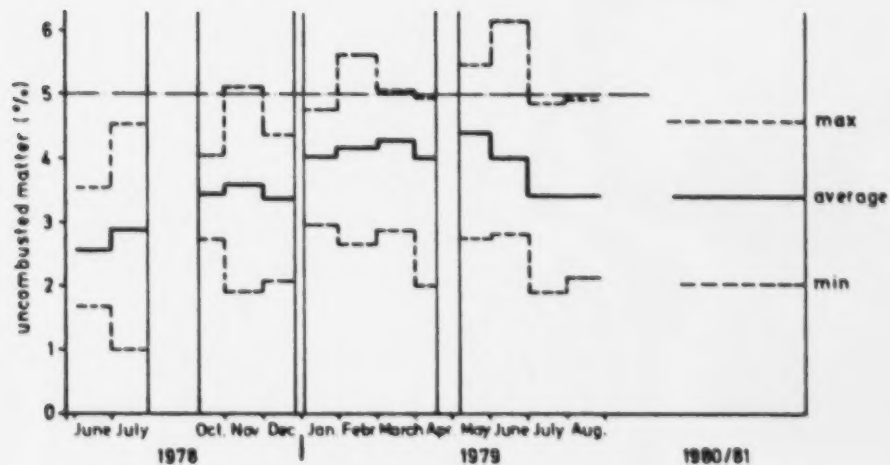


FIG. 4 UNCOMBUSTED CARBONACEOUS MATTER IN FLY ASH, VARIATION WITH TIME.

A crosscheck with fly ash obtained from an unstaged operation, which was possible due to the retrofit burner compromise (reuse of old burner with controllable tertiary air streams), gave however no change in fly ash composition. This indicated that the fly ash problem had to be attributed mainly to another cause which was found in the mill system. The mills had run more than 15 000 hours without any change of wear parts, resulting in an increase in particle size distribution up to 42 % > 90 μ m. After changing the wear parts of the mills and an appropriate adjustment of the classifiers the unburnt matter in fly ash could again be reduced to an average of 3.5 %, as shown for the 2nd half of 1979 in Fig. 4.

This large scale demonstration program at a 700 MWe boiler has proven the applicability of SM-burner concept.

No detrimental side effects were encountered. Since already five large coal fired boilers with more than 3500 MWe capacity have been sold with this combustion technology. They will come into operation from 1986 onwards.

4 PARAMETRIC STUDIES ON IN SITU DESULFURIZATION AND ITS LARGE SCALE APPLICATION

Similar to the de NO_x technology development, pilot tests were carried out at IFRF/IJmuiden to investigate the feasibility of direct desulfurization by the injection of sorbents into the flame periphery (ref. 9) and create a basis for further tests to be conducted in a large-scale boiler.

A series of tests was carried out with a pilot scale burner of 2.3 MW thermal output, however only the most important results will be commented here. A more detailed report has been given in ref. 4, 5 and 6.

The experiments were carried out in two phases. In the first phase the experiments were carried out using natural gas cut with SO₂ or H₂S as a model fuel to demonstrate the complex reactions involved in the attainment of a reaction of the first order when heterogeneous phases are involved. Using a precisely defined natural gas flame ($n = 1.20$; $n_p = 0.6$; swirl = min.) the influence of the remaining parameters as listed below on desulfurization was investigated. In the second phase, the experiments were carried out with three different bituminous coals and here, partly because of the different sulfur binding structure in each case, the parameters n , n_p and swirl were changed. In order to afford a comparison with previous work (ref. 2, 3, 10), the additives were also blown in with the fuel.

The following significant parameters were tested:

- Fuel
natural gas cut with SO₂ or H₂S and three different bituminous coals
- Additive
Ca(OH)₂, CaCO₃ and activated Ca(OH)₂
- Molar ratio Ca/S
from 1 - 4
- Point of additive injection on burner
with fuel, with staging air, through tubes in the external recirculation zone
- Air flow ratios at burner
total air n, primary zone stoichiometric ratio n_p
- Flue gas temperature
from 900 °C - 1100 °C
- Swirl
from minimum to maximum
- Load
from 60 % to 150 %
- Velocity of staging air
low and high

For the presentation of results the percentage degree of desulfurization η_{SO_2} for a definite molar ratio Ca/S is defined as follows:

$$\eta_{SO_2} = \frac{(SO_2)_1 - (SO_2)_2}{(SO_2)_1} \cdot 100 \dots\dots\dots (1)$$

Here (SO₂)₁ represents the SO₂ concentration of the flue gases as measured immediately before the injection of additive. (SO₂)₂ represents the SO₂ concentration measured during injection of additive at a definite molar ratio. Thus this definition also takes into account any binding of SO₂ which may occur on the furnace walls and in the flue gas probe.

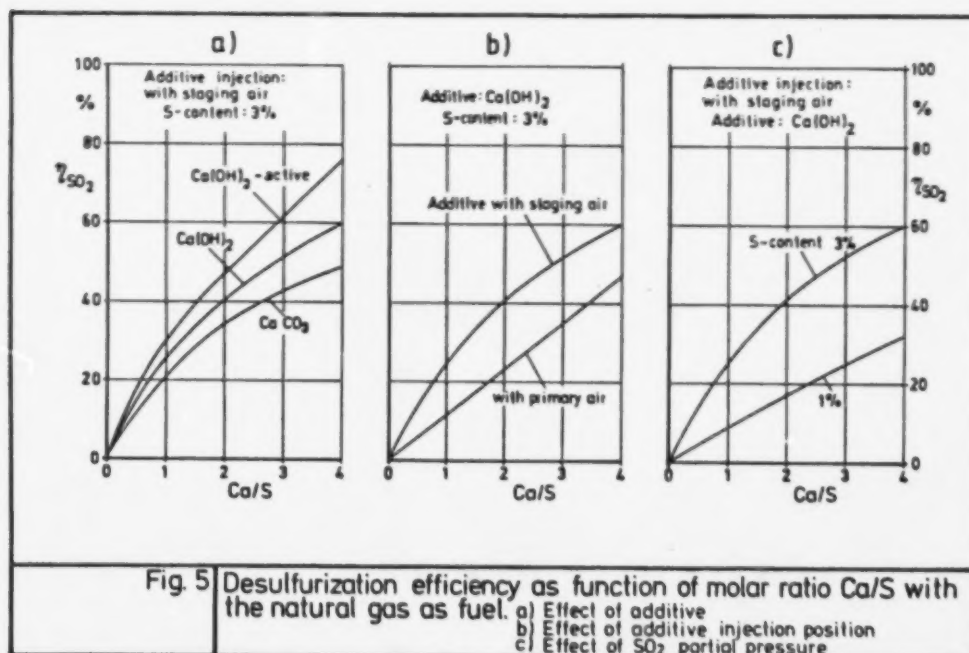
To establish the molar ratio Ca/S, the sulfur content which was measured in ultimate analysis of the fuel is taken as a basis.

4.1 Experimental Results with Natural Gas

Fig. 5 shows the influence of additive type, point of additive injection and sulfur content of the natural gas upon the sulfur capture $\%SO_2$ as a function of the molar ratio Ca/S. Desulfurization increases in less than direct proportion to the increase of the molar ratio Ca/S.

Three kinds of additive were injected into the furnace to bind the sulfur: limestone $CaCO_3$, calcium hydroxide $Ca(OH)_2$ and activated calcium hydroxide $Ca(OH)_2$. All additives were in a very finely powdered form: 50 % of the $Ca(OH)_2$ particles being below $4 \mu m$, 50 % of activated $Ca(OH)_2$ below $7 \mu m$ and 50 % below $12 \mu m$ in the case of $CaCO_3$.

According to Blaine, the specific surface area for $CaCO_3$ then measures $0.456 m^2/g$, for $Ca(OH)_2$ $1.86 m^2/g$ and for activated $Ca(OH)_2$ $1.034 m^2/g$. All three additives were manufactured and supplied by Messrs. RWK Kalkwerke, Dornap/Wuppertal. This company also holds the patent for activated calcium hydroxide. In the preparation of the activated calcium hydroxide used in the experiments, the quicklime was ground with the addition of fatty acids and hydrated using calcium chloride solution. The product thus contains 2.44 % calcium chloride, which acts as a catalyst.



The type of additive has a quite definite effect on sulfur absorption and Fig. 10a shows that CaCO_3 has less affinity for sulfur than Ca(OH)_2 , while activated Ca(OH)_2 only offers improved desulfurization when the concentration of SO_2 in the flue gas is very high. The test results indicated that at lower SO_2 concentrations in the flue gas the rate of diffusion of the SO_2 towards the additive may well restrict the sulfation process, whereas at high SO_2 levels sulfation reaches a maximum value which depends on the properties of the additive, but is no longer limited by diffusion of SO_2 towards the additive surface.

Fig. 5b shows the influence of the additive injection location upon the degree of desulfurization. Injection direct into the flame heart produces a lower degree of desulfurization than when the additive is injected into the outer recirculation zone of the flame e.g. via the staging air. The tendency of lower desulfurization when Ca(OH)_2 is injected with the transport air can be viewed as a result of longer residence times for the particles in the hot flame zones, with consequent sintering of the surfaces, resulting in considerably reduced activity and low stability of any CaSO_4 which may be formed.

As Fig. 5c shows, binding of sulfur is more effective when the sulfur content of the fuel is high, at least up to a certain SO_2 concentration. This can partly be explained by a higher decomposition temperature of the CaSO_4 , and greater diffusion of SO_2 to the surface of the additive.

The other parameters mentioned influence desulfurization only when the temperature pattern in the flame or furnace is altered as a result.

The levels of desulfurization achieved with natural gas were unsatisfactory from the point of view of use in full-scale boilers and it made no difference whether the additive was introduced with the primary air or peripherally. The reason why the tests were nevertheless continued with bituminous coal can be seen from the comparison of the results from experiments with natural gas and those with bituminous coal (ref. 3). The following facts could be deduced:

- 1) Our own natural gas experiments and the bituminous coal experiments in (ref. 3) both showed higher desulfurization as a result of peripheral injection.
- 2) Injection of the additive produces a lower degree of desulfurization with natural gas than with the bituminous coal of ref. 3.

There was thus the prospect of increasing the degree of binding of SO_2 with bituminous coal both through injection of additive with the fuel and in the external recirculation zone as well.

4.2 Experimental Results with Bituminous Coal

The most important results can be summarised as follows:

- By direct injection of calcium hydroxide powder into the turbulent diffusion flame it is possible to absorb sufficient amount of sulfur released as a result of combustion and present mainly as sulfur dioxide.
- Fig. 6 shows the maximum measured desulfurization levels achieved with various fuels as a function of the molar ratio Ca/S, using Ca(OH)_2 as additive.

The additive was injected into the outer recirculation zone of the flame. For Ca/S = 2 the following degrees of desulfurization were measured:

- 50 % for Ruhr coal from the Auguste Viktoria mine, with a maximum SO_2 concentration in the raw gas of 2385 mg/m^3 (STP dry)
- 57 % for Saarland coal from the Götteleborn mine, with a max. SO_2 concentration in the raw gas of 1810 mg/m^3 (STP dry)
- 65 % for Ruhr coal from the Blumenthal mine, with a max. SO_2 concentration in the raw gas of 7712 mg/m^3 (STP dry)
- The best results were obtained in each case when the additive was injected round the periphery of the burner into the outer recirculation zone of the flame and combustion was staged according to the following pattern: a fuel-rich primary zone in the flame in which NO_x emissions were reduced by about 50 %. The concept of combustion with lower NO_x and SO_x emissions would thus seem to be a feasible one.
- With the staged mixing burner tested, the local point of injection of additive had a material influence on sulfur binding. Injection with the tertiary air produced a somewhat lower degree of sulfur binding than injection through the tubes in the external recirculation zone. However, if the additive is mixed, with the transport air, the degree of desulfurization may be reduced to as little as 50 % of the above-mentioned values.
- Since calcium sulfate is not stable at the concentrations of SO_2 normally found in flue gas burning german coals and temperatures of 1200°C plus, injection of additive into the flame core cannot be an effective method in view of the extended residence time of the additive in the high-temperature zone.

Additionally, sintering of the CaO particles begins at around 1250 °C and this inactivates the surface of the particles.

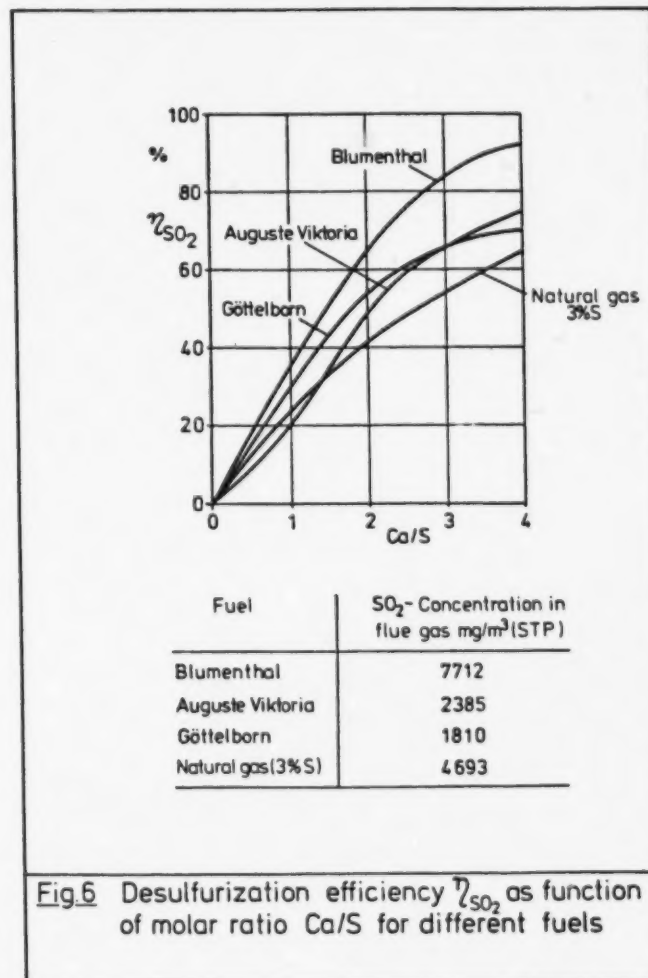
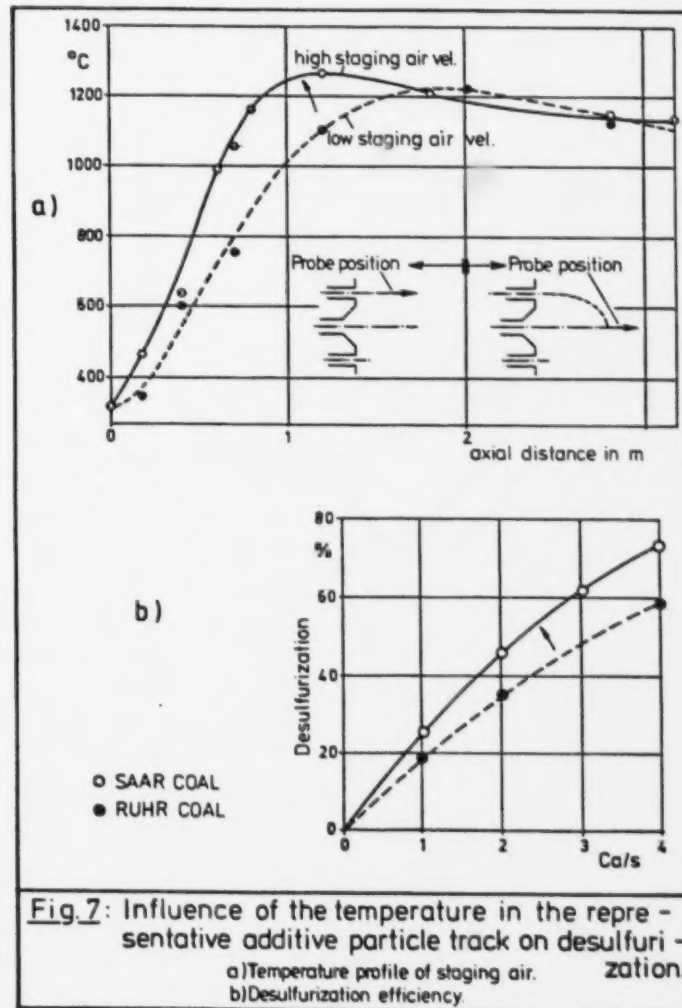


Fig.6 Desulfurization efficiency η_{SO_2} as function of molar ratio Ca/S for different fuels

- The analysis of solids samples and temperature measurements along the mean additive particle track, together with the known decomposition temperature of $CaSO_4$, lead to the conclusion that the thermal conditions acting on the additive have a decisive effect upon the process as a whole. The temperature and desulfurization data presented in Fig. 7 demonstrate this clearly for bituminous coal firing, measured along a representative additive particle track. On the basis of the aerodynamic and temperature measurements in the furnace, it was assumed that the particle track is identical with the axis of the staging air stream for a distance of approx. 2 m and then at distance of 3 m from the burner throat bends inwards towards the flame axis. Increasing the velocity of

the staging air independent of the quantity causes more intensive mixing of staging air and flue gas, which results in faster heating of the airstream. Additionally, it was observed that at higher staging air velocities the flame is wider. The explanation for this phenomenon is that the higher kinetic energy of the staging air tends to entrain the primary air flow. Analysis of the solids samples shows that unburnt coal is entrained into the staging air flow and there burned, with the result that its thermal output further heats up the staging air.

As Fig. 7b shows, an initial fast heating of the additive and subsequent minimal residence times at high temperatures offer better conditions for desulfurization. The levels of desulfurization shown in Fig. 7b are however not the maximum values measured.



- Independent of the sulfur content the fuel quality has a definite influence on SO_2 binding. While the different coal varieties all showed similar behaviour in this respect, the tests on natural gas cut with SO_2 as in Fig. 6 gave very poor desulfurization figures for all methods of injection. The only possible explanation for this is that at the higher temperatures involved in natural gas firing - definitely higher than with coal - the formation of CaSO_4 is hampered.
- Absorption of the sulfur in the flue gas became more effective as the SO_2 concentration increased, at least up to a certain concentration of SO_2 (Fig. 5c). Experimental results suggest that below a definite SO_2 concentration in the flue gas, the rate of diffusion of the gas towards the additive particles is possibly so low as to restrict the formation of sulfates with the additive, whereas at high SO_2 concentrations sulfation rises to a maximum value which depends on the properties of the additive, but is not limited by the problem of slow diffusion of SO_2 towards the additive surface.

The maximum sulfation capacity of the sorbent which can effectively be attained with coal of high sulfur content probably depends upon the thermal influences to which the additive is exposed in the furnace, but is also decisively influenced by the original properties of the sorbent. Under the most favourable conditions, i.e. high SO_2 concentrations and suitable injection conditions, the following maximum value for calcium efficiency η_{Ca} in the transformation of CaO into CaSO_4 are:

- 34 % for Ca(OH)_2
- 23 % for CaCO_3
- 50 % for activated Ca(OH)_2

where the equation

$$\eta_{\text{Ca}} = \frac{\eta_{\text{SO}_2}}{\text{Ca/S}} \dots\dots\dots (2)$$

obtains, having regard to the definition of Ca/S given in this paper.

- Under optimal injection conditions an increase in the thermal input to the furnace or a reduction of the heat output from the furnace causes a reduction in desulfurization because of the increased furnace temperatures which result.
- High excess air in general produces a slight increase in desulfurization.

4.3 Large scale application

4.3.1 Economic Analysis

The primary step for the assessment of the market potential of a novel process is an economic evaluation - especially when a novel technology has to replace fully or partially existing proven technologies to become successful.

On the basis of the desulfurization efficiencies worked out in the pilot experiments the cost of applying the Steinmüller Direct Desulfurization Process "DEP" to a 700 MW_{el} power station was reckoned. The cost was then compared with those ensuing when a wet-system FGD unit producing gypsum as the end-product was employed.

The following boundary conditions were included in the projection for both units:

Fuel:	Bituminous coal
	Sulfur content 1 %
	Ash 7 %
Flue gas:	SO ₂ concentration 2200 mg/m ³ (STP dry)
Clean gas:	Desulfurization efficiency 72 %
	SO ₂ concentration 616 mg/m ³ (STP dry)
	For FGD it was assumed that 80 % of the flue gas flow was treated, with a desulfurization efficiency of 90 %
Additive:	For DEP: Ca(OH) ₂ molar ratio Ca/S = 4
	For FGD: CaCO ₃ molar ratio Ca/S = 1.05
	(Ca/S refers to the S content of the coal)

The total costs are made up of investment, operating and personnel costs. For DEP the operating costs are the most significant, and they consist essentially of the costs for additive, dumping and/or transportation costs for solid effluents, cleaning the heating surfaces and for auxiliary power. These operating costs are some 50 % higher than for FGD. The investment costs, however, represent only some 10 % of those required for FGD.

Investment costs for DEP are mainly for the additive dosing equipment (bunkers, fans, dosing mechanisms, pipework, control system, etc.), the increased number of sootblowers and the increase in size of the electrostatic precipitators. Personnel costs are reckoned as some 1 : 3 in comparison with FGD.

When calculating the investment costs on an annual basis, a basic interest rate of 8 % p.a. was assumed for the investment capital required, and an amortisation time of 15 years. These figures gave a redemption factor of 11.7 %.

To this, the annual depreciation and interest on investment capital, a cost factor of 1.1 (10 % of invested capital) for administration, repairs and taxes has been taken in account, giving a total investment cost per annum equivalent to 21.7 % of the capital cost of the plant.

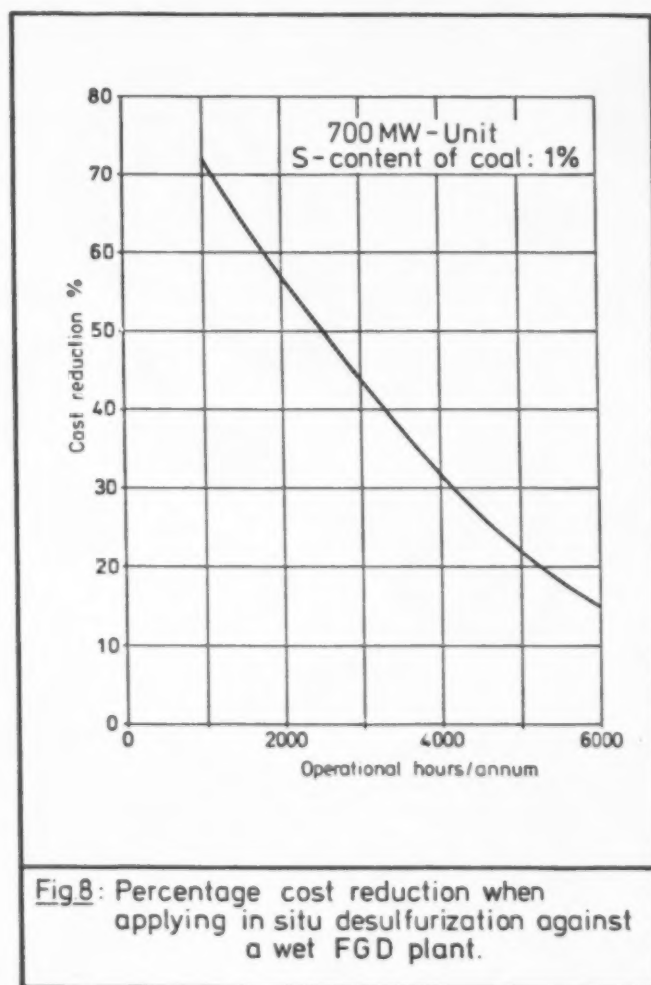


Fig. 8 shows the percentage reduction of desulfurization costs when using DEP instead of FGD with gypsum as by-product.

The reduction in costs is reckoned for full load firing and depends on the number of operating hours per year. Because of the high investment costs of FGD, progressive reduction in operating hours per year produces a considerable cost advantage for DEP. For a medium power station running 4000 hrs per annum the reduction in costs would be over 30 %.

The economic advantages of DEP increase as the sulfur content of the coal diminishes and with reducing size of plant. In particular, existing units, which for reasons of space cannot install FGD equipment, can very easily be reterofitted to Steinmüller in situ desulfurization process "DEP".

Thus further efforts for the technology development still required are justified by the large scope of advantages of the in situ de SO_x -process.

Before the commercialisation of the process is justified, however, following potential problem areas which might be prohibitive for the application of in situ de SO_x under some circumstances have to be investigated:

a) Membrane wall slagging in the radiant section of the boiler.

Although the presented technology is anticipated to avoid these problems due to avoidance of mixing of fuel and the calcium based sorbent, only experiments can identify if the well known detrimental effect of CaO with respect to slagging behaviour of coal ash can be avoided sufficiently well (ref. 3).

b) Fouling of convective banks and air preheater in the boiler.

In spite of the only moderate increase of the solid burden in the flue gas the change in composition - especially the formed CaSO_4 might influence the fouling characteristics.

c) Fly ash removal efficiency of the ESP.

The sorbent addition leads to an increase in solid burden of the flue gas the more the higher the sulfur content of the fuel respectively the required de SO_x efficiency is. This and the change of the ash characteristics with changing composition might have a detrimental effect on the ESP efficiency.

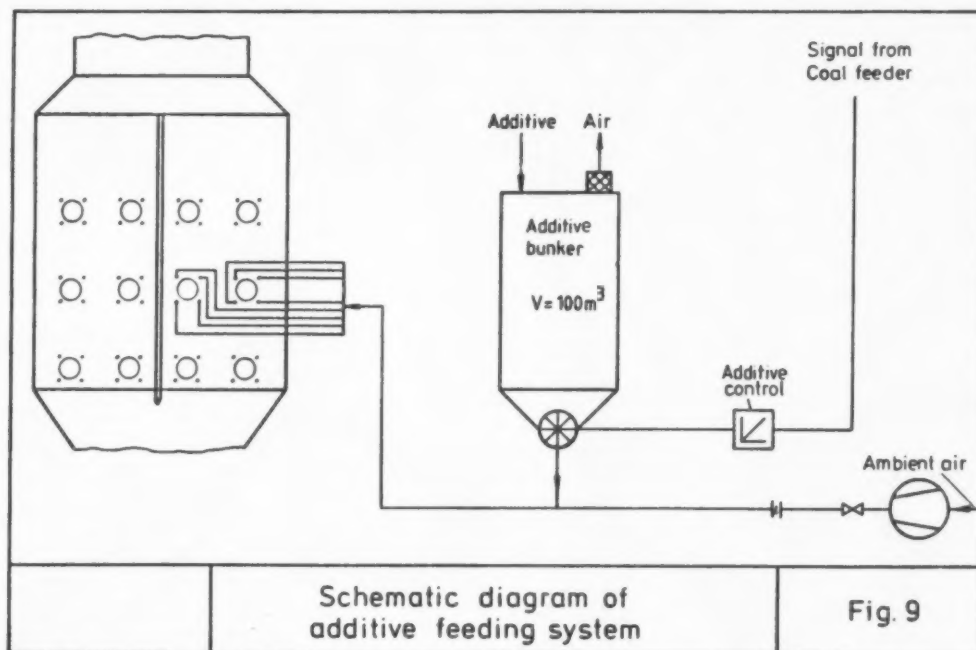
d) Change of ash composition.

Due to the certain change of ash composition present users of fly ash might question the applicability of this ash within their process causing sales or dumping problems.

e) Level of desulfurization

The pilot experiments were carried out with a single burner. In a large utility boiler, by contrast, there are a number of burners arranged alongside and above each other. This causes very complex flow patterns in the furnace which can create a different temperature distribution from that in the test furnace for the pilot experiments. As the results already obtained demonstrate, the temperature/time history of the injected additive is of decisive importance for the absorption of SO_2 , and therefore definite data on the level of desulfurization can only be obtained by experiments with the aforementioned large boiler.

To assess the severity of these problem areas an investigation program is presently being executed at the 700 MWe boiler which was retrofitted with low NO_x staged mixing burners in 1978. This investigation program has been subdivided into two phases. In the first phase, which has been recently finished, two of six burners at one of the burner walls were operated with sorbent injection (fig. 9). The aim carrying out these trials was to foresee, if there are any severe detrimental effects on the burner or boiler tubes especially in the vicinity of the burner and to optimize the additive injection system.



The positive results from these two burners have encouraged us to start with the second phase. Now all the 24 burners are being retrofitted with Steinmüller direct desulfurization process. The trials could start in the late summer 1983.

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LOW-NO_x TANGENTIAL SYSTEM
SO_x CONTROL THROUGH SORBENT INJECTION

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ABSTRACT

A tangentially fired, pilot-scale combustor is being used to determine the potential of a low-NO_x "air-on-wall" combustion modification technique to simultaneously reduce SO_x emissions through a dry sorbent injection technique. The pilot-scale facility has been designed to simulate fuel/air mixing and bulk gas heat transfer events characteristic of full-scale tangentially fired utility boilers. The results from the initial phase of the program, baseline NO_x/SO_x testing, are described in the paper. The baseline testing discussed here was carried out under the conventional tangential burner configuration. The gas temperature profile measured in pilot scale is shown to agree satisfactorily with full-scale data. Also, NO_x emission levels from the pilot-scale facility are in excellent agreement with those of full scale. Dry sorbent injection tests were conducted to show the effect of SO_x reduction as a function of sorbent injection concentration, excess air, furnace load, sorbent injection location, sorbent type, and coal type. The trends observed in the dry sorbent injection tests are consistent with past studies. Actual SO_x reduction levels achieved are also similar. The effect of overfire air addition on dry sorbent injection is briefly discussed.

INTRODUCTION

Increased NO_x and SO_x emissions resulting from increased usage of coal for power generation could exacerbate the acid rain and smog problems the United States is currently facing. To control these problems, emissions reduction technology must be developed for coal-fired boilers. Among the various types of coal-fired boilers, tangential coal-fired boilers are significant users of fuel and producers of NO_x and uncontrolled SO_x emissions (1). Demonstrating cost-effective NO_x and SO_x reduction technology for these boilers will provide regulatory agencies with additional emission reduction options which could be exercised in the future to prevent environmental degradation.

For the past several years, Acurex has supported the EPA in developing a combustion modification technique for controlling NO_x from tangential

coal-fired boilers. This effort has led to the "air-on-wall" concept (2), which has the following system features:

- Fuel directed at conventional tangential yaw angle into the center of the furnace
- Some secondary air (fuel air) directed parallel to the fuel jet
- The bulk of the secondary air directed along the wall above and below the fuel jet elevation ("air-on-wall")

These system features create oxygen-deficient conditions in the active near burner and the vortex core zone, an important condition for NO_x reduction, and oxygen-rich conditions on the furnace walls, an important condition for the prevention of watertube corrosion. A schematic of the concept is shown in figure 1. Pilot-scale tests at 293 kW (1 million Btu/hr) have demonstrated a maximum of 60 percent reduction in NO_x from conventional tangentially fired systems (see figure 2) with no deterioration in combustion efficiency (2, 3, 4). Initial full-scale tests of this concept by Combustion Engineering in a 65-MWe boiler have been successful. Using the same concept, but with different percent "air-on-wall" flows, they achieved a maximum reduction of 40 percent.

With NO_x control technology in hand, the current research has emphasized SO_x emissions control by direct sorbent injection. Sorbent material, such as lime or limestone, or more generally alkali-metal oxides, is injected into the hot zones of a furnace where it can react with the sulfur from the fuel to form sulfates, sulfites, or sulfides. The resultant solid products are then removed from the flue gas along with flyash by conventional ash recovery systems. The dry sorbent injection concept requires no special type of reactor, and equipment requirements are limited to conveyer and storage bins for handling the sorbent, a pulverizer and injection system, if sorbent is to be added separately from fuel, and probably additional dust removal equipment. Accordingly, it may be retrofitted into existing powerplant systems without major modifications and thus with a relatively low investment. The capital investment for dry sorbent injection is estimated to be in the range of \$20 to \$100/kW depending on unit size, sulfur content of the coal, and sorbent concentration (5). If dry sorbent injection can be shown to remove 50 to 70 percent of the sulfur in the coal at reasonable sorbent stoichiometries, it will have definite economic advantages over the other sulfur removal technologies, which require capital investments in excess of \$100/kW.

The direct sorbent injection method is not a new concept and has been tried by several investigators in the past. Investigations include the European work in the sixties (6, 7) and the U.S. work in the seventies (8 to 12), which were performed primarily in bituminous coal-fired boilers. As shown in figure 3, most of these attempts were not very successful in that the efficiency of sorbent utilization remained quite poor. These relatively poor results were attributed to the loss of sorbent reactivity when exposed to excessive heat in the furnace, and to mixing problems when sorbents were injected above the heat release zone.

Recent direct sorbent injection test results were more encouraging. There are indications that SO_x reductions of over 50 percent at a Ca/S of 2 are achievable, which makes the direct sorbent injection method economically more attractive than other desulfurization methods.

The recent work differs from the past work in at least two ways. For the RWE (Rheinisch-Westfälisches Elektrizitätswerk) work (13), dry sorbent injection tests were carried out in a 60-MWe boiler firing brown coal which is characterized by its high moisture and ash content. This study showed that SO_x reduction of well over 50 percent could be achieved at Ca/S = 2.5 using calcium hydroxide as the sorbent. The high moisture content limited the peak flame temperature to approximately 1423K, which is significantly lower than the bituminous coal flame temperatures, thereby providing a better time-temperature profile for sulfur capture. The inherent calcium contained in coal ash provided additional sulfur capture capability. These two unique properties did not exist in the coals tested in the past work.

Work performed by the International Flame Research Foundation (IFRF) (14, 15) and Energy and Environmental Research Company (EERC) (16), tested the direct sorbent injection method in a low- NO_x , front-wall-fired, multistage burner. While the past work was performed using standard burners, it could be envisioned that the temperature as well as the chemical field of the low- NO_x burner would be more attractive to sulfur capture. There are zones in low- NO_x multistage burner systems where oxygen is deficient. Consequently, the sorbent may react with sulfur in the forms of H_2S , COS , and CS_2 in addition to SO_x . The peak flame temperature in multistage burner systems is also expected to be lower than standard burners due to the delay in heat release. This may also provide a better time-temperature profile for sulfur-sorbent reactions. These studies showed that the potential exists for achieving over 50 percent reduction in SO_x levels at reasonable sorbent feedrates (Ca/S = 2).

These two features of the low- NO_x front-wall-fired systems are also present in the tangentially fired "air-on-wall" system. In this system, a fuel-rich zone exists in the vortex core, as shown in figure 4 (2). The peak flame temperature of the low- NO_x "air-on-wall" system is expected to be lower than conventional systems due to the delay in heat release. These two features should make dry sorbent SO_x control effective in tangentially fired systems. Given this potential, the objective of the current effort is to determine the feasibility of simultaneously reducing NO_x and SO_x in the pilot-scale tangentially fired facility through dry sorbent injection.

FACILITY DESCRIPTION

A schematic of the pilot-scale research furnace system is given in figure 5. The geometry of the furnace represents an approximate 1 to 14 scaling of an existing modern design Combustion Engineering, tangentially fired boiler. Overall height is 3.7m (12.0 ft) above floor level, and the firebox interior cross section is 0.9m by 1.1m (3.0 ft by 3.5 ft).

Two burner levels are situated at each corner of the firebox. Each corner burner set includes two primary air jets as well as fuel/annular air, auxiliary air, and overfire air ports. The primary air and fuel/annular air jets have a small degree of firing angle variability -- up to 8° from the

firebox diagonal. All other air jets can be varied from the diagonal to parallel to the wall to achieve optimum low- NO_x conditions. Each of the burner tube sets can also be exchanged for other sets to achieve major variations in combustion air velocity.

The combustion gases travel upward and through the horizontal and downflow convective sections and then into a baghouse filter. An ID fan is mounted in the stackline downstream of the baghouse to provide balanced draft or negative firebox pressures. The nominal firing rate for this facility is approximately 0.4 MJ/s (1.5 million Btu/hr). Fuels are either gas or coal.

The firebox, convective section, and ashpits are all cast refractory-lined to prevent excessive heat loss. Heat extraction tube bundles are situated throughout the convective section, and also on the firebox roof, to provide an appropriate combustion gas temperature-time profile. The heat extraction loop is a closed system, utilizing a high boiling temperature organic liquid (Dowtherm) as the heat extraction medium and an air-cooled heat exchanger for controlling the Dowtherm temperature.

The coal feed system consists of eight feed lines (two burners per corner), and a screw feeder system that incorporates four independently controlled augers. Each of the four coal streams is picked up pneumatically and then split into two separate streams to achieve the required eight feed lines. The system allows firing of the two burner levels or furnace corners at different heat release rates.

The sorbent feed system consists of a single auger-controlled screw feeder assembly and a pneumatic sorbent transport system. The sorbent/air mixture can be injected into the furnace through a single port, or it can be passed through a four-way distributor and injected into the furnace at each corner. The large number of access ports incorporated into the furnace allows a great deal of flexibility with regard to sorbent injection location and method.

The flue gas recirculation blower provides up to 40 percent recirculation at the nominal 0.4 MJ/s (1.5 million Btu/hr) firing rate. Exhaust gases at up to 478K (400°F) are mixed with combustion air and can be injected into a variety of burner locations.

Thermocouples are located throughout the facility and temperatures are monitored constantly. Emissions are normally sampled at the end of the convective section where the gas temperature is around 533K (500°F). O_2 , CO_2 , CO, unburned hydrocarbons, NO_x , and SO_2 levels are monitored and recorded.

RESULTS FROM TEST PROGRAM

The sequence for the test program is given in figure 6. Initial characterization of the pilot-scale facility is carried out in the baseline NO_x/SO_x testing task. This is to ensure that the pilot plant has a realistic time-temperature profile as well as comparable emission levels to a full-scale tangentially fired boiler. All the baseline NO_x/SO_x testing consists of firing coal in the conventional tangential burner configuration; that is, the fuel and the auxiliary air jets are positioned at 6° from the firebox

diagonal. After completion of this task, the facility will be characterized for low- NO_x conditions utilizing the "air-on-wall" concept. In this second phase of the program several low- NO_x conditions will be selected, and then, in the third phase, the selected low- NO_x conditions will be tested with dry sorbent injection for simultaneous reduction of NO_x and SO_x emissions.

Only the baseline NO_x/SO_x testing task has been completed to date, and the results presented in this paper are from this initial testing phase. The following discussion will consist of temperature profile simulation as well as NO_x/SO_x emission characterization.

Baseline Testing -- Temperature Profile

Temperature characterization of the pilot-scale facility was carried out firing an Illinois no. 6 bituminous coal. The furnace centerline temperature profile, starting from a sampling location directly above the burner level to the midconvective section was measured using a bare thermocouple. The measured temperature profile is shown in figures 7 and 8, in terms of the radiant section temperature profile and the convective section temperature profile, respectively. Also shown in figures 7 and 8 are full-scale data for comparison purposes (17, 18).

Figure 7 shows that the pilot-scale data agree reasonably well with the full-scale data, although they are generally lower by less than 5 percent. Since pilot-scale temperatures were measured using a bare thermocouple, while the full-scale temperatures were measured by a suction pyrometer, a more favorable comparison can be achieved if the pilot-scale data are corrected for heat loss. Suction pyrometer measurements in the pilot-scale facility are scheduled to be carried out in the very near future.

Figure 8 shows the comparison of pilot- and full-scale system temperature profiles in the convective section. As can be seen, the pilot-scale temperatures lie within the range of field data for the temperatures of interest, especially for sulfur capture.

Baseline Testing -- NO_x Emissions

The NO_x emissions from the tangentially fired facility were measured and compared with full-scale data to evaluate pilot-scale simulation capability. Full-scale data obtained from the recent Utah Power and Light (UPL) tests (19) and published literature (20) were used as a basis for comparison. NO_x emission measurements were taken burning the identical Utah bituminous coal that was used in the UPL tests. Tests were carried out with and without overfire air (OFA). The results are presented in figures 9 and 10, respectively, in terms of NO_x emissions versus excess oxygen, and percent NO_x reduction versus percent secondary air introduced as OFA.

Figure 9 shows that the 0 and 10 percent OFA pilot-scale data agree excellently with the full-scale data, while the 15 percent OFA pilot-scale data is 10 to 15 percent lower but is consistent in trend compared with the full-scale data. It should also be noted that OFA tests at UPL were obtained at damper openings of greater than 60 percent, which corresponds to approximately 9 to 15 percent OFA. Since the exact amount of OFA is not

readily defined, the full-scale data was compared to pilot-scale data obtained at 10 to 15 percent OFA, respectively.

Figure 10 compares published full-scale data on tangentially fired systems with the pilot-scale data in terms of NO_x reduction versus OFA. The agreement between the two scales is excellent, confirming that appropriate simulation has been achieved in the pilot-scale facility. The good agreement of the temperature profile and NO_x emissions between the pilot-scale and full-scale systems has enhanced the viability of using the pilot-scale facility as a vehicle to study NO_x/SO_x control techniques.

Baseline Testing -- SO_x Emissions

SO_2 emissions¹ were monitored from the tangentially fired pilot plant and the effects of sorbent injection were investigated. The nominal firing rate was 1.5 million Btu/hr and the nominal excess air level was 20 percent. None of the secondary air was added as overfire air in these tests. The majority of the SO_x baseline tests were carried out burning an Illinois no. 6 bituminous coal and injecting El Dorado limestone. This limestone sorbent is a high-purity CaCO_3 stone mined in northwestern California; the particle size of the material was held constant during the tests at 99 percent under 44 μm .

The parameters investigated in this sequence of dry sorbent injection tests include:

- Calcium to sulfur ratio
- Excess air
- Load
- Sorbent injection location
- Sorbent type
- Coal type

The results are shown in figures 11 to 15.

Figure 11 shows that for sorbent injection at the OFA level, a baseline SO_2 concentration of 3,800 ppm, SO_2 emissions were reduced by approximately 20 to 30 percent at $\text{Ca/S} = 1$ and by approximately 40 to 50 percent at $\text{Ca/S} = 2$. As is consistent with past studies, an increase in sorbent feedrate usually results in improved SO_2 reduction primarily due to better sulfur/sorbent contact under highly nonequilibrium conditions. However, higher sorbent feedrates will lead to uneconomical sorbent costs, as well as adverse effects

¹In the baseline SO_x tests, sulfur gas emissions were measured using a SO_2 analyzer and thus, in this subsection, sulfur emissions results will be reported as SO_2 . However, the terms SO_2 and SO_x ($\text{SO}_x = \text{SO}_2 + \text{SO}_3$) are used interchangeably because the amount of SO_3 is usually negligible in flue gases generated under normal atmospheric combustion conditions.

on electrostatic precipitator performance and slagging/fouling characteristics. $\text{Ca/S} = 3$ is considered to be the practical, and also economical, upper limit for sorbent injection concentration. In our test program, $\text{Ca/S} = 2$ will be the baseline sorbent injection concentration and $\text{Ca/S} = 3$ the maximum.

Figure 11 also shows the effect of excess air on SO_2 reduction. At Ca/S ratios of 1 and 2, sulfur capture was greater for the higher excess air case than for the lower excess air case. Over 50 percent reduction was achieved at a Ca/S ratio of 2 for the 30 percent excess air case. This trend is identical to some studies that have shown that higher excess air levels in the combustion gases are beneficial for the formation of CaSO_4 (11, 12, 21).

The effect of furnace load is depicted in figure 12. Sulfur capture roughly doubles to approximately 40 percent at $\text{Ca/S} = 1$ as a result of the decrease in combustor firing rate. Lower furnace temperatures were observed during low-load firing, and this probably created an improved residence time-temperature profile for sulfur/sorbent reactions.

As shown in figure 13, injection of sorbent at the burner level reduces sulfur capture by approximately 75 percent compared to the OFA injection case. This result may be attributed to the higher flame temperatures in the burner zone, which can deadburn the sorbent particle and thus limit its reactivity. Sorbent injection location has been one of the most critical parameters in achieving good SO_2 reduction. Because of the different operating conditions of past dry sorbent injection tests, there is no consensus on an optimum injection location. The general goal, however, is to inject the sorbent into a zone which will provide the most optimal residence time-temperature relationship for the particle. Deadburning of the sorbent must be avoided and, at the same time, sulfur/sorbent contact must be maximized to ensure that reactions do occur.

Figure 14 shows SO_2 reduction as influenced by sorbent type. The baseline sorbent, El Dorado limestone, is 98 percent CaCO_3 and, as mentioned previously, is mined in northwestern California. The second sorbent used in this test is Gibsonburg dolomite, which is approximately 58 percent CaCO_3 and 40 percent MgCO_3 . The dolomite is mined and processed in Gibsonburg, in northern Ohio. Judging by the geological location of the mines, the El Dorado and Gibsonburg sorbents are expected to differ in physical structure as well as chemical composition. This implies that there may be some difference between the two sorbents in terms of reactivity toward sulfur capture. The particle size ranges of the two sorbents were identical at 99 percent below $44\text{ }\mu\text{m}$ so that a consistent comparison could be obtained. Figure 14 shows that, despite their differences in composition and structure, the limestone was only slightly better in SO_2 reduction compared to dolomite. The reason for the closeness of data cannot be clarified at this time, and it requires more detailed examination of the two sorbent materials.

The effect of coal type on SO_2 reduction is shown in figure 15. The Illinois coal is a midwestern bituminous containing a relatively high level of sulfur (3.5 percent). The UPL coal is the one used in the baseline NO_x testing sequence, and it is a low-sulfur (0.5 percent) western bituminous coal from central Utah. It is clear from this figure that, at comparable calcium

to sulfur injection ratios, the percent SO_2 reduction is greater (approximately 300 percent) for the coal which is inherently higher in sulfur. This trend is consistent with several past studies that have shown that SO_2 reduction is higher for coals with higher sulfur content (11, 14). Higher sulfur content implies higher partial pressure of sulfur species in the combustion gases, which should affect sulfur/sorbent reaction.

Figure 16 shows a comparison between the pilot-scale data with full-scale dry sorbent injection data obtained from tangentially fired coal-burning boilers. For conditions where sorbent was injected at the OFA ports, good agreement between pilot- and full-scale SO_2 reduction data was obtained. For conditions where sorbents were injected into the flame zone, the pilot-scale data were consistently lower. Although the exact experimental conditions could differ considerably between the pilot- and full-scale dry sorbent injection tests, the SO_2 reduction levels in pilot scale reflect the actual field data and are consistent in trend.

Finally, figure 17 shows the effect of sorbent injection location on SO_2 reduction with OFA. Forty percent of the total air was admitted as OFA, thus creating a fuel-rich zone at the burner level. As shown in the figure, the two injection locations (OFA and burner level) produced very similar levels of SO_2 reduction. Comparison of figure 17 with figure 13 shows that the addition of OFA somewhat reduced the SO_2 capture when injecting through the OFA ports while improving SO_2 capture significantly (approximately 300 percent) when injecting at the burner level. The differences were probably caused by the creation of a different time-temperature environment by the addition of OFA. The improvement in SO_2 reduction using burner level injection may have also been due to a fuel-rich zone that could have enhanced sulfur capture. Such analysis is only speculative at this time, and further experiments are being carried out in the pilot-scale facility to clarify these effects.

CONCLUSIONS

A multilevel, tangential-burner pilot-scale research facility has been designed and constructed to study simultaneous NO_x and SO_x reduction. The initial phase of the testing program, baseline NO_x/SO_x testing, has been completed. All baseline testing was conducted using the conventional tangential-burner configuration. The gas temperature profile measured in pilot scale agrees satisfactorily with full-scale data. Pilot-scale NO_x emission data also show excellent agreement with full-scale data, with and without OFA. Dry sorbent injection tests demonstrated that SO_x reduction increases with increased sorbent feedrate, increased excess air, decreased furnace load, and increased coal sulfur content. This conclusion is consistent with past studies. Sorbent injection was shown to be more effective through OFA ports than at burner level, and there was only a slight difference in sulfur capture capabilities between two sorbent materials (limestone and dolomite). The addition of OFA improves SO_x capture through burner level injection while it worsens capture through OFA port injection. In summary, the baseline dry sorbent injection tests conducted in the pilot-plant facility, using a conventional tangential-burner configuration, produced SO_x capture levels comparable to past studies conducted on full-scale boilers.

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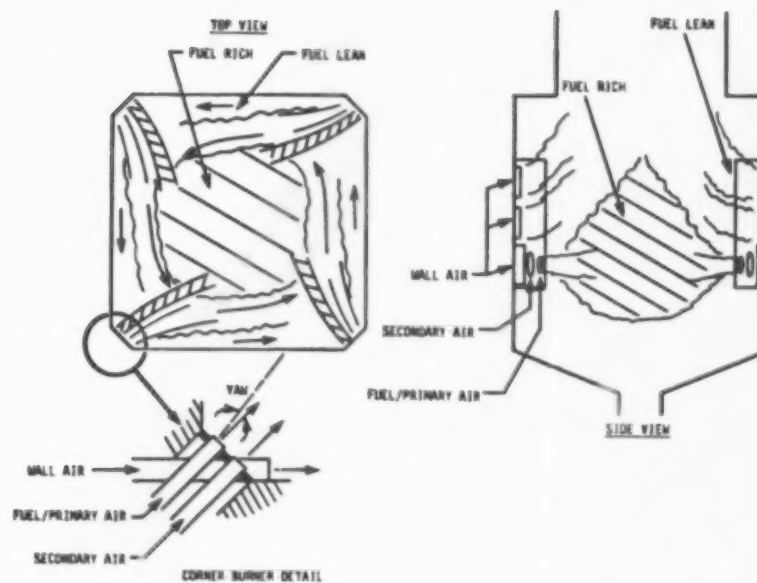


Figure 1. Pilot-scale air-on-wall system schematic.

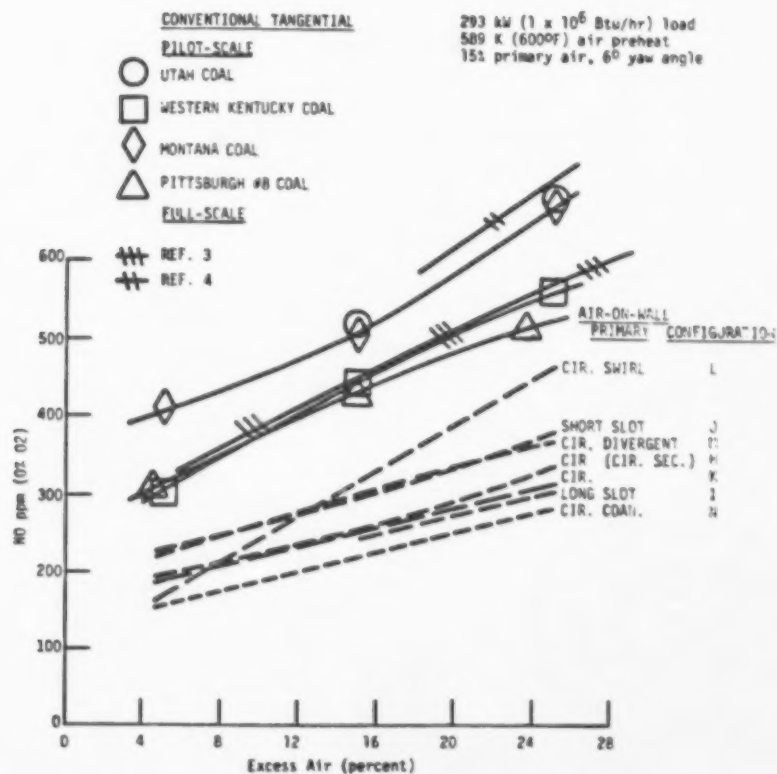


Figure 2. NO emissions versus excess air.

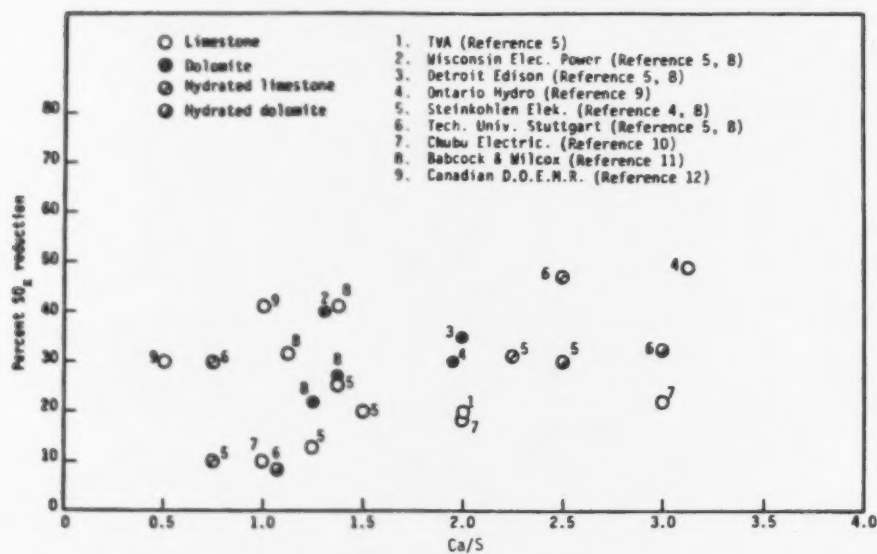


Figure 3. Percent SO₂ reduction as a function of sorbent concentration.

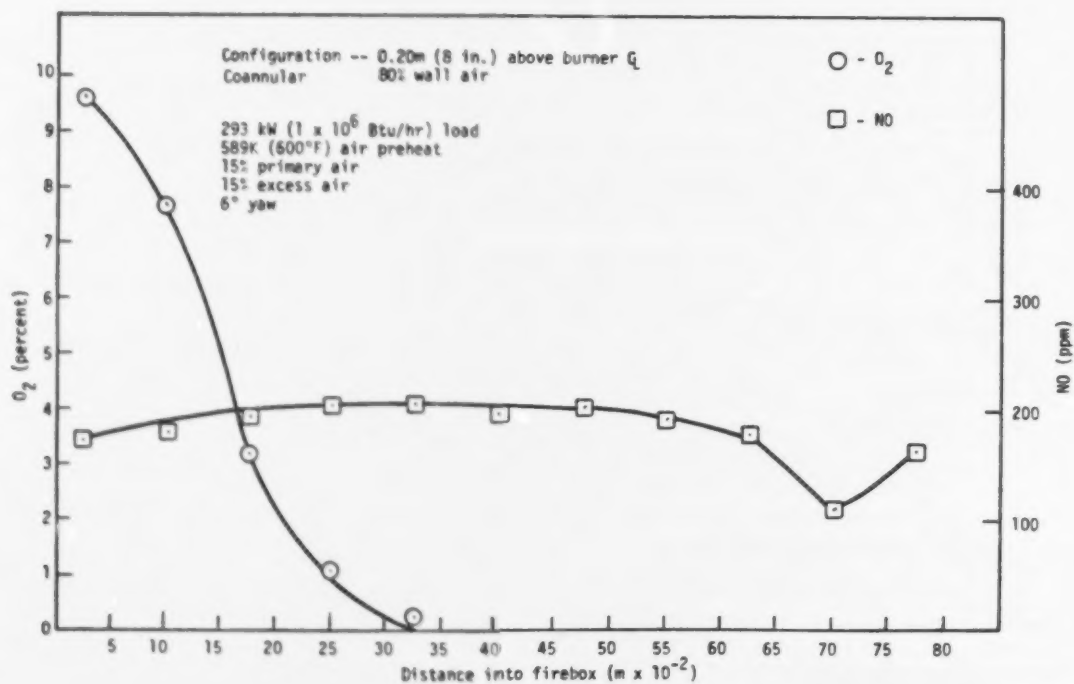


Figure 4. Air-on-wall configuration -- NO and O₂ firebox concentrations 20 cm above the fuel entry elevation.

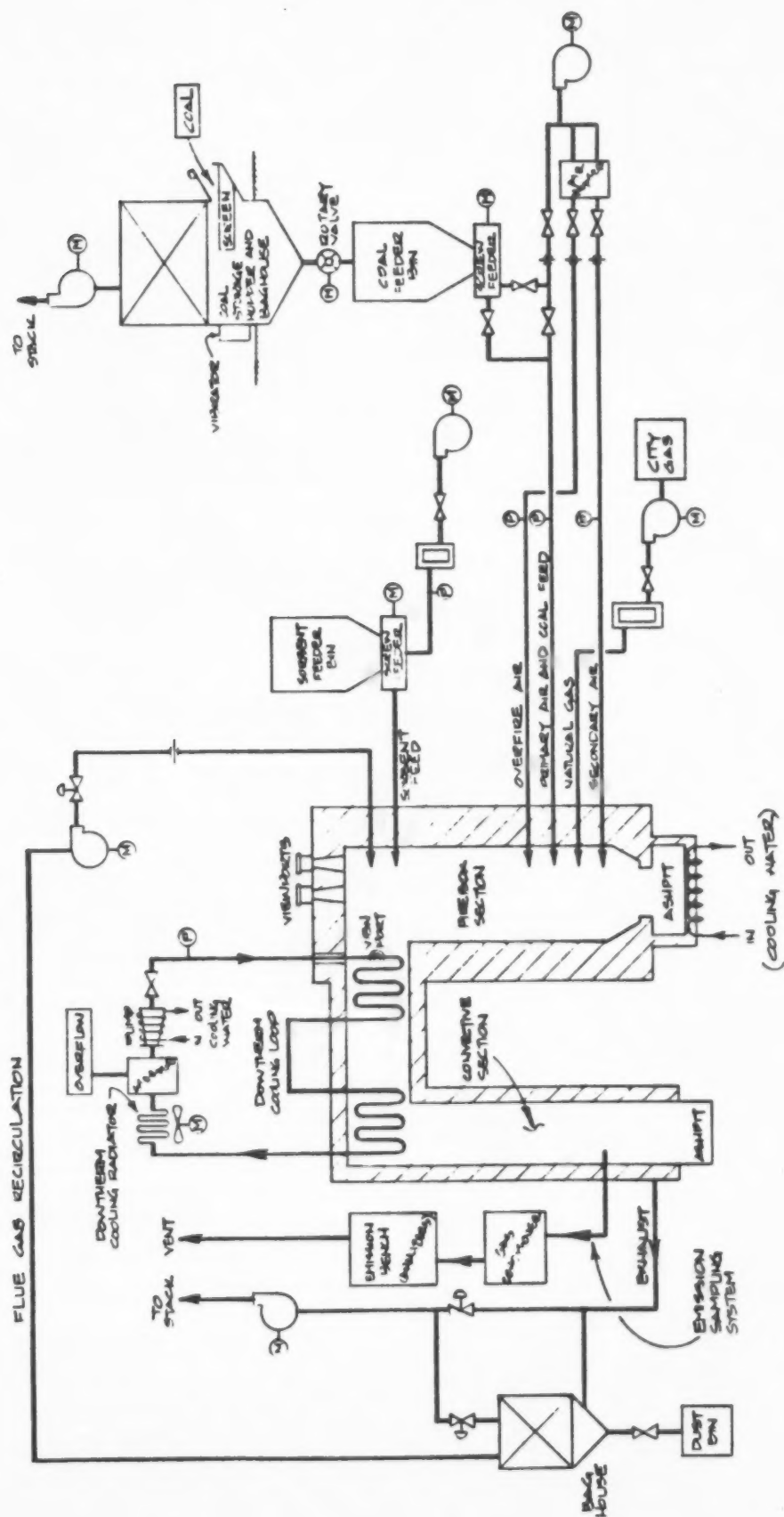


Figure 5. EPA Pilot-scale research furnace system.

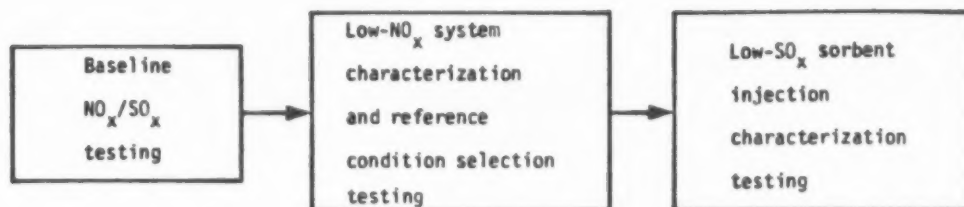


Figure 6. Testing sequence for low-NO_x/SO_x program.

Pilot-Scale Test Conditions:

Date: 9 July 1982
 Fuel: Illinois #6 Bituminous
 Burner Configuration: Conventional
 Firing Rate: 1.5×10^6 (Btu/hr)

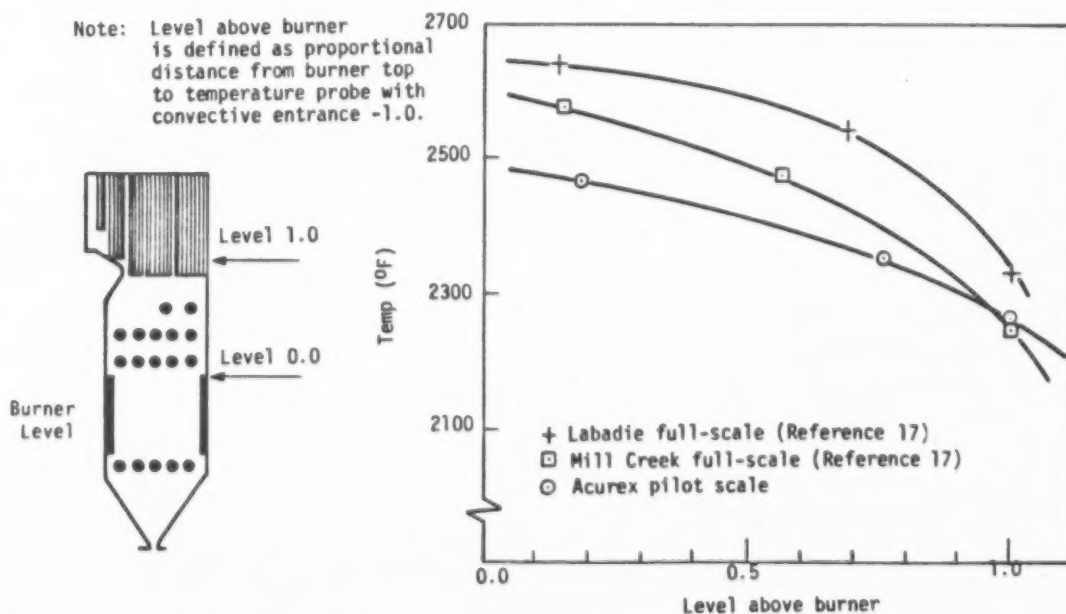


Figure 7. Comparison of temperature in the radiant section — full-scale vs. pilot-scale.

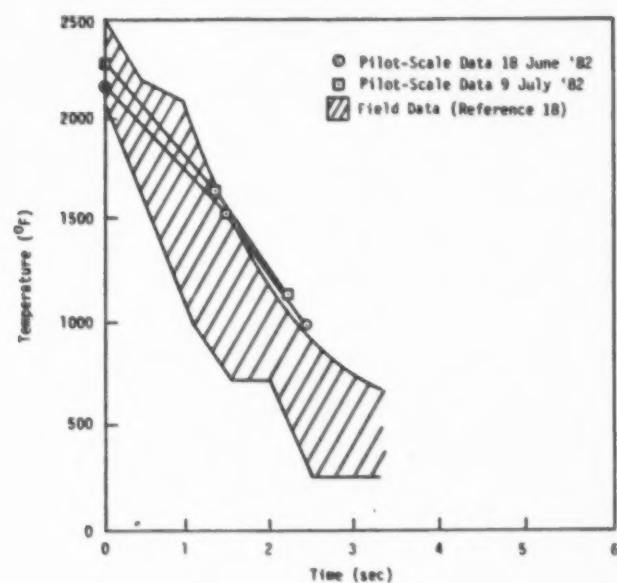


Figure 8. Comparison of temperature in the convective section — full-scale vs. pilot-scale.

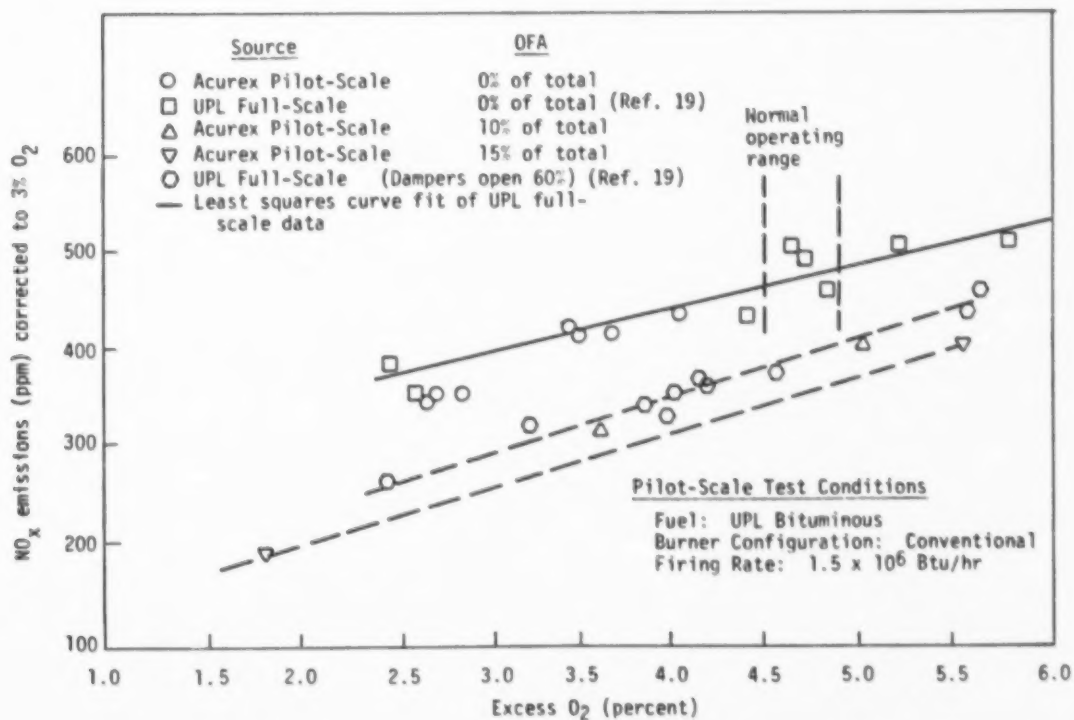


Figure 9. Comparison of pilot-scale and full-scale NO_x emissions for tangentially fired systems.

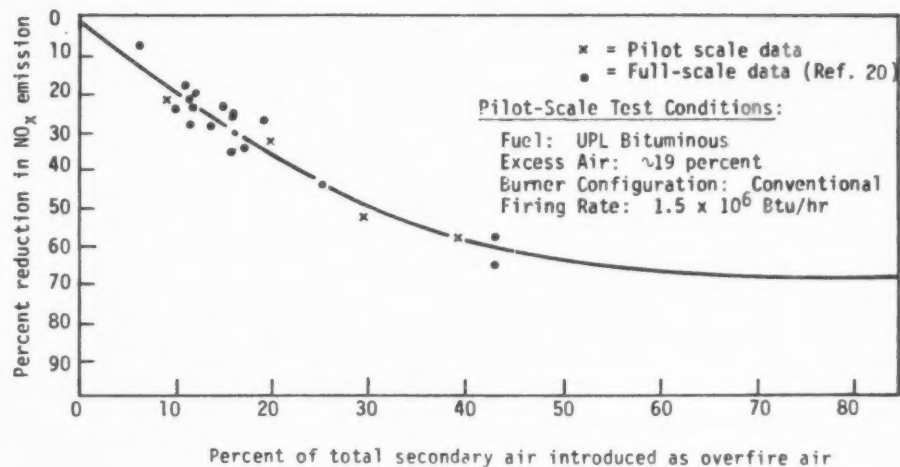


Figure 10. NO_x reduction achieved by overfire air control technology.

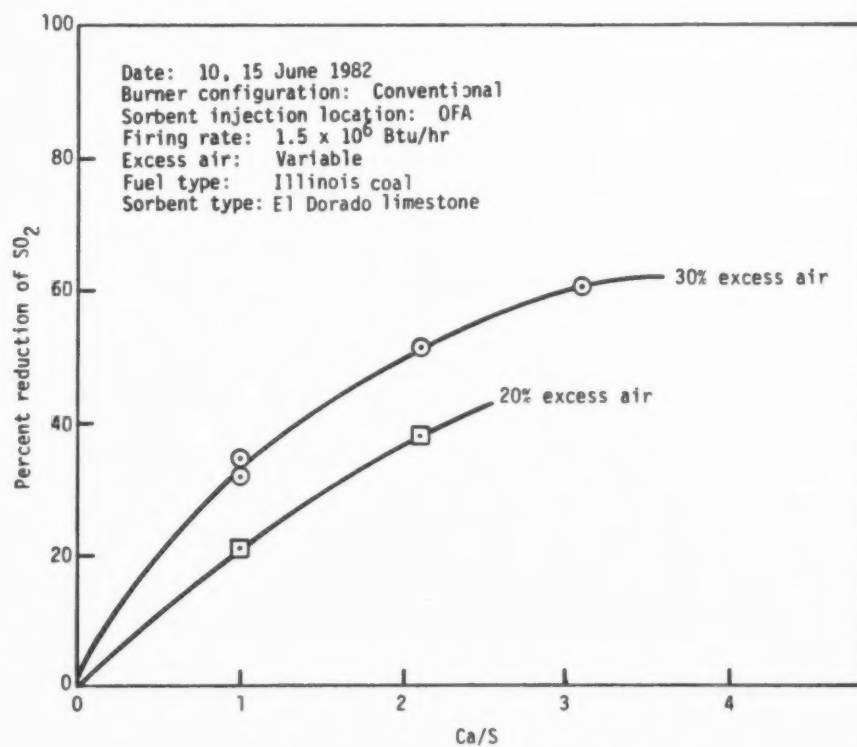


Figure 11. Effect of excess air on percent reduction of SO_2 .

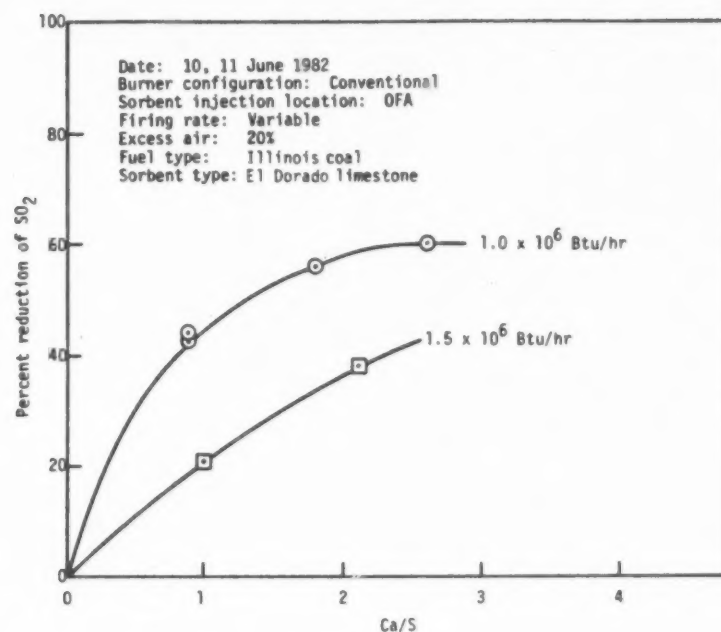


Figure 12. Effect of load on percent reduction of SO₂.

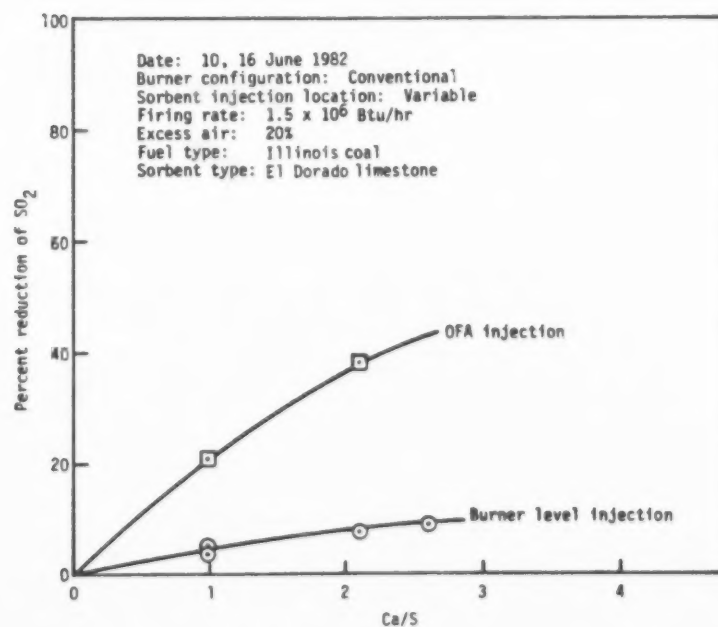


Figure 13. Effect of sorbent injection location on percent reduction of SO₂.

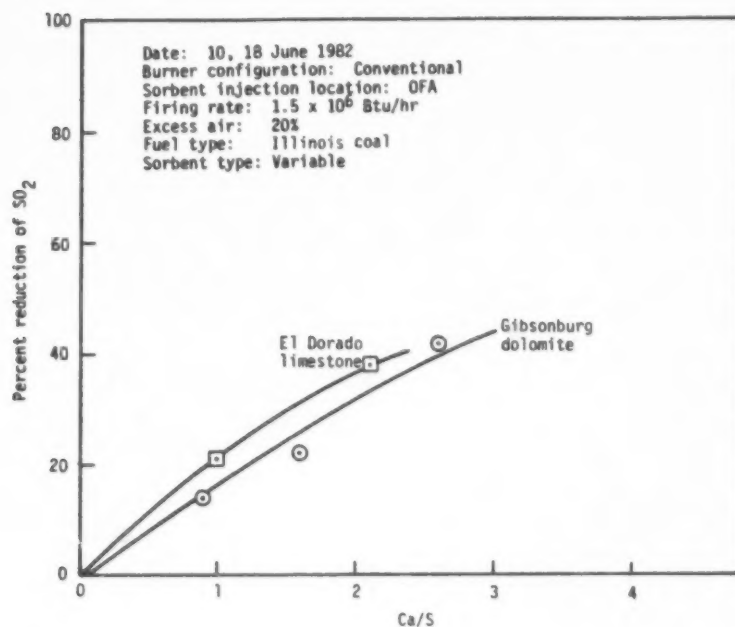


Figure 14. Effect of sorbent type on percent reduction of SO_2 .

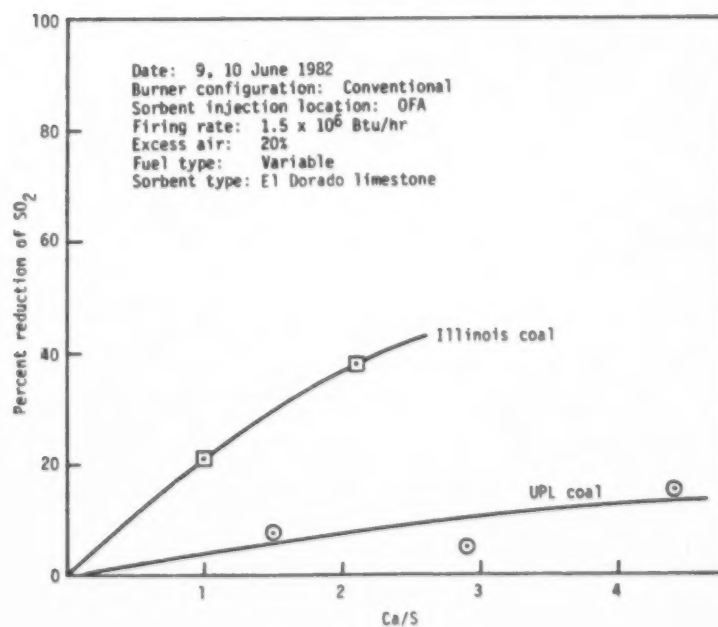


Figure 15. Effect of coal type on percent reduction of SO_2 .

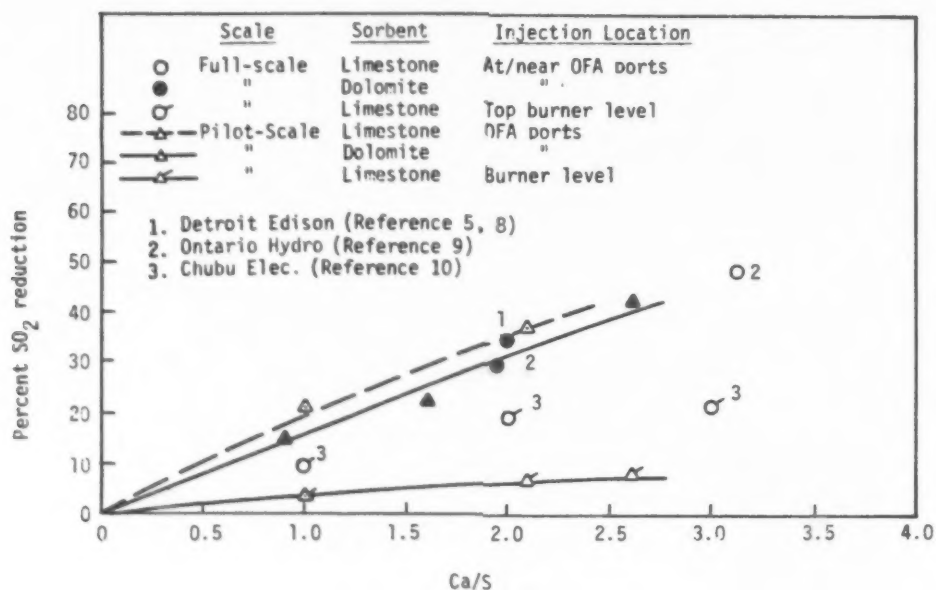


Figure 16. Percent SO_2 reduction as a function of sorbent concentration compared with field data.

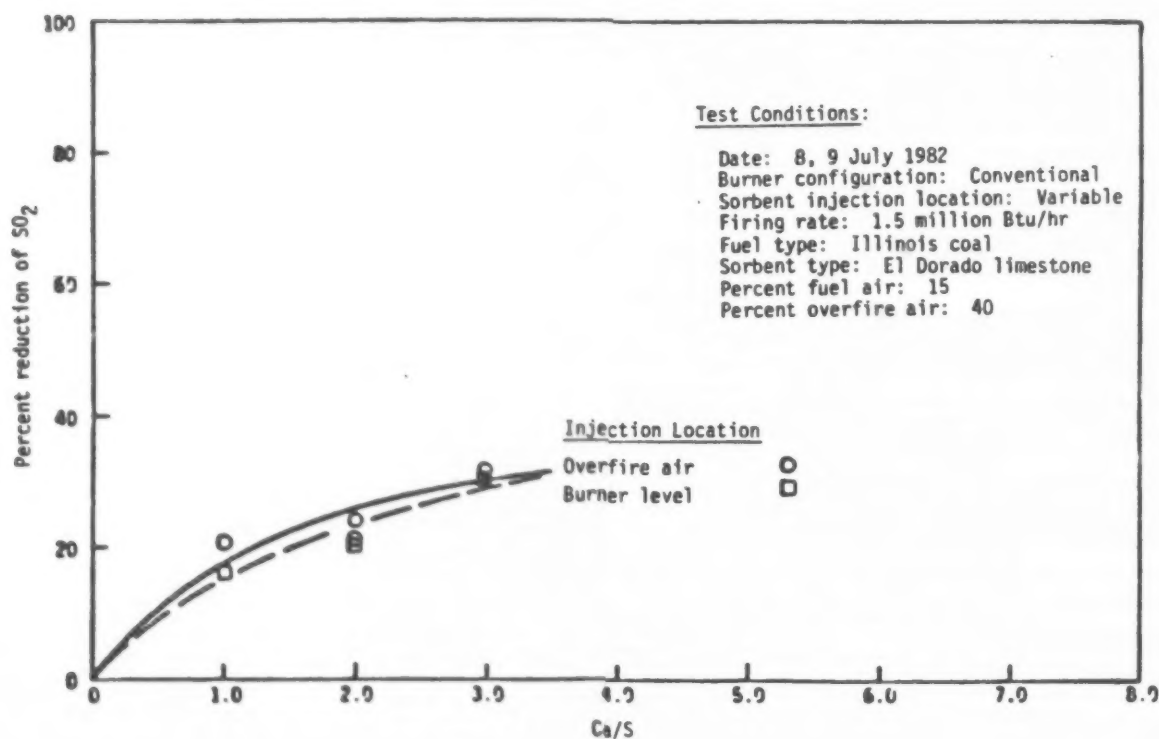


Figure 17. Effect of overfire air on percent reduction of SO_2 .

"FEASIBILITY OF FURNACE INJECTION OF LIMESTONE FOR SO₂ CONTROL"

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ABSTRACT

A four-phase program under EPRI sponsorship to determine the engineering and economic feasibility of dry sorbent injection for control of sulfur dioxide emissions has been completed. A survey of available literature on dry sorbent injection for sulfur control was performed which was supplemented by laboratory ash fusion temperature tests of selected coals at several Ca/S ratios. The information generated from these studies formed the basis for an engineering feasibility and an economic impact analysis for both new and retrofit utility boiler applications.

An analysis of sixteen case studies was performed relating Ca/S and coal sulfur content to boiler design and dry sorbent system costs. The analysis showed that dry sorbent injection is feasible from an engineering point with levelized costs of 1 mills/kWh to 14 mills/kWh depending on the coal sulfur content and the Ca/S molar ratio.

INTRODUCTION

In the early 1960's, the concept of direct limestone injection into the furnace cavity of a utility boiler for control of SO₂ emissions originated as a means for reducing SO₂ without involving utility companies in sophisticated chemical flue gas treatment systems. It was felt at the time that direct injection of limestone followed by wet particulate scrubbing was the least complicated and most economical procedure for meeting anticipated SO₂ as well as particulate removal requirements. However, various trials of this concept at small scale furnaces and full scale utility boilers generally failed to demonstrate sufficient in-furnace SO₂ removal at reasonable sorbent to sulfur ratios. Even at injection rates of three to four times the stoichiometric requirement, SO₂ removals of no greater than 70 percent were reported. These results combined with boiler operational concerns essentially discredited this approach and the development of wet SO₂ scrubber systems became the focus of SO₂ control efforts.

The high temperatures and oxidizing conditions typical of conventional utility boiler furnaces are now suspected to have created conditions

highly unfavorable for SO_2 sorption and in retrospect these early results are not surprising. However, the development of advanced low NO_x utility boiler combustion technologies may provide substantially new combustion conditions and lower furnace gas temperatures which fortuitously appear to be highly suited for successful sorbent removal of SO_2 . Utilization of the low NO_x combustion process to capture SO_2 via direct injection of limestone or other reactants into the combustion zone represents a new technology with the possibility of simplifying as well as offsetting the costs of the overall environmental control system of a coal fired power plant.

OBJECTIVE AND SCOPE

This paper presents the results of a program that was sponsored by the Electric Power Research Institute to determine engineering, operational, and economic feasibility of direct furnace injection of sorbent for SO_2 control under low NO_x conditions. The program had four major tasks:

- 1: Background information survey on sorbent injection for SO_2 control.
- 2: Laboratory ash fusion tests and chemical analyses of selected coals and sorbent/coal mixtures.
- 3: Engineering and operational feasibility assessment on a current 500-MWe utility boiler to determine applicability for new and existing boilers. Analysis of furnace injection at sorbent to sulfur molar ratios up to 4:1 to determine the effects on system design and boiler performance.
- 4: Economic evaluations including both capital and operational costs of systems designed in Task 3.

The results from each of these tasks is discussed in this report along with recommendations for future research.

BACKGROUND INFORMATION SURVEY

Available literature and inhouse experience were reviewed concerning the theoretical and practical aspects of injection of alkaline earth materials into fossil fuel fired boilers for the purpose of sulfur dioxide absorption. This information included numerous publications covering about a 15 year time span beginning with work conducted in the late 1960's. Information was sought in various areas pertaining to materials handling, SO_2 removal and impact on design and operation of boiler and auxiliary equipment. Specific areas included:

- SO_2 removal efficiency
- Sorbent type
- Limestone storage and handling
- Limestone injection scheme

- Flame stability and proving
- Combustion efficiency
- Automatic control of limestone injection
- Fireside slagging, fouling and corrosion
- Convective pass erosion
- Ash distribution, removal and disposal
- Air preheater performance
- Effects of limestone carryover on particulate controls and scrubbers
- Limestone recycle

SO₂ Removal Efficiency

In the various commercial scale investigations of furnace sorbent injection conducted in Japan, Europe and the United States throughout the 1960's an SO₂ absorption limit of approximately 25% was observed for both dolomite (CaCO₃ - MgCO₃) and limestone (CaCO₃) injection. The pilot scale work of that same era showed results of 45 to 60 percent SO₂ absorption with sorbent-to-sulfur stoichiometric ratios of up to 4:1. (The highest sulfur absorption levels were achieved with those additives having the greatest surface area in a given time/temperature situation.) It was concluded that the discrepancy between pilot scale and the commercial scale results was due to different combustion temperatures, i.e. pilot scale tests typically were conducted in furnaces set at approximately 1500 to 2100°F (816-1149°C) and commercial scale tests were conducted in furnaces operating at approximately 2400 to 3000°F (1316-1649°C).

Interest in direct additive injection to control SO₂ emissions subsided for a few years and was replaced by flue gas desulfurization techniques. However, recent investigations with low NO_x burners and with boilers burning "brown" coal, both of which have the effect of lowering combustion zone temperatures, has rekindled interest in limestone injection. These investigations have reportedly yielded SO₂ absorption levels as high as 60 to 90 percent when using limestone, depending upon the fuel type, burner configuration, and sorbent-to-sulfur stoichiometry.

Sorbent Type

Available literature on the relative sulfur removal efficiency of several of the more common forms of calcium was reviewed. The following list shows the consensus of removal efficiencies in decreasing order:

- | | |
|----------------------------------|-----------------------------|
| 1. Hydrated lime | 4. CaO (calcined limestone) |
| 2. Dolomite | 5. Marl |
| 3. CaCO ₃ (limestone) | 6. Shell |

Only limestone (raw and/or calcined) is available currently on a large enough scale nationally to be used economically for boiler injection. It is felt that raw limestone (CaCO₃) will prove to be the better additive for several reasons. First, limestone will not require calcination, which

increases an additive's initial cost and, second, although raw limestone will require extra heat input to the boiler (more coal) to calcine it (approximately 600 Btu's/lb (1396 kJ/kg) limestone), the added cost of hydrated lime appears to outweigh any increase in sulfur removal efficiency. In addition, the tendency of the calcined limestone (CaO) to deadburn in the boiler results in an increase in total additive required.

Limestone Storage and Handling

Limestone handling and storage can be carried out with essentially the same equipment conventionally utilized for coal. Commercially available components have been combined in the various demonstration systems and the "systems" operated successfully.

Initially, in this study, consideration was given to pulverization of limestone concurrently with the coal. Adequate control of limestone particle size resulted in excessive mill rejects and upon review of the properties of coal and limestone, separate milling was adopted. (Limestone is denser than most coals, which leads to limestone losses in pulverizer wastes because pulverizers are designed and set to provide a selected particle size when grinding materials of a similar hardness and density.)

Limestone Injection Scheme

The literature review also revealed pertinent information regarding the design of an injection system, additive injection point, and related effects on boiler and auxiliary equipment performance and design. Studies by Battelle, TVA, and others have determined that additive porosity and particle size are two variables that affect the overall SO_2 absorption process. Conclusions have been drawn, based on electron-microprobe scans, that the SO_2 absorption reaction is largely confined to the external surface of the particles. Internal porosity did increase the capacity for reaction. However, porosity is mainly a function of the type/origin of the sorbent, and therefore, the optimum sorbent type was determined by the cost and the availability.

For CaO injected directly into furnace, absorption of SO_2 is poor compared to other additives such as CaCO_3 or Ca(OH)_2 which must first decompose in the gas stream. Whether the improved performance with these latter additives is due to the internal overpressure creating more and larger pores or reducing the particle size is not known.

Separate pulverization followed by injection of the limestone in the windbox or fuel nozzle region of the boiler modified for low NO_x firing appeared most promising. This should provide maximum mixing of coal and limestone particles and avoid subjecting the limestone particles to peak flame temperatures which could lead to deadburning and deactivation.

From the most recent EPA studies it has been concluded that maximum reactivity is realized when the average particle size passes 90% through 325 mesh (15 microns). Increased fineness beyond this level may reduce limestone reactivity. Extremely fine particles may overheat very rapidly, before they can react with the sulfur, creating a deadburning effect.

Many different injection schemes have been tried for limestone injection. From these many tests, several criteria for injecting limestone to achieve the most beneficial results have been determined: (1), maximize the residence time that the limestone particle has in the "critical" temperature region (region between 1700°F and 2500°F (927°C and 1371°C) is critical in that this is where the calcium/sulfur reaction to form calcium sulfate is most favorable), (2), minimize the time during which the limestone particle is subject to overheating and thus, deadburning (above 2700°F) (1482°C), (3), maximize the particle surface area (as discussed earlier), and (4), maximize the mixing that takes place between the limestone and coal particles.

Flame Stability

During earlier testing reviewed in this study there was no evidence that addition of limestone in the burner region at levels contemplated as practical (maximum Ca/S ratio of 4) would have any adverse affect on flame stability nor would the limestone be expected to interfere with flame scanning operations.

Combustion Efficiency

Limestone requires approximately 600 Btu/lb (1396 kJ/kg) for calcining; thus the heat available for steam generation will be reduced accordingly. Previous experience with furnace injection indicates that complete calcination of limestones is easily achieved and in fact overburning is a more likely concern.

Automatic Control of Limestone Injection

Control systems described in the literature have usually been set up to feed according to coal sulfur levels based on boiler load and fine tuned on the basis of stack SO₂ emissions. Current thinking suggests that a control system based on this reasoning continues to be appropriate.

Fireside Slagging, Fouling and Corrosion

The performance of boiler heat transfer surfaces during full scale demonstrations with sorbent injection, have varied. The sorbents' effects on slagging and fouling ran the full gambit from no adverse effects to major reheater plugging, to plugging of the boiler economizer, superheater, and air heater. These results suggest that the slagging and fouling tendencies of a coal/sorbent mixture are functions of the particular coal. This contention is further supported by results from laboratory ash fusion

tests reported in a later portion of this paper. Preliminary tests pertaining to fireside corrosion with sorbent injection have shown no adverse results.

Convection Pass Erosion

Erosion and pluggage of rear pass heat transfer surfaces is not thought to be a problem attributable to the physical properties of limestone. However, the increased quantity of dust generated during limestone injection may require increased sootblower coverage.

Ash Distribution, Removal and Disposal

When the ash from a limestone injected boiler is collected dry with an ESP or bag filter it is desirable to avoid contact with water until the material is conveyed to its ultimate disposal. Dry/wet interfaces in the ash removal system may be a source of plugging or deposit buildup which would reduce the capacity of the ash conveying system. An ash removal and conveying system that is completely dry would be optimal. The increased particulate loading resulting from furnace injection of limestone will require increased operating frequency of sootblowers and the ash conveying system.

Air Preheater Performance

Studies performed on air heaters during limestone or dolomite injection have shown that with reduced SO_3 levels in the gas stream, plugging, as indicated by pressure drop across the air heater, is reduced to a minimum. While the ash loading is increased the actual deposit buildup decreases and that which forms tends to be fluffy and readily removable. Low temperature probe studies conducted during full scale limestone furnace injection studies showed that SO_3 was reduced to a sufficiently low level that corrosion was eliminated and deposits were dry and generally non-adherent.

Precipitator/Scrubber Performance

Studies on precipitator performance during limestone injection have provided varying results with regard to efficiency. However, the outlet particulate matter loading was sufficiently increased as to be unacceptable. In one case no apparent change in efficiency was reported while decreases in efficiency from the 90 - 95% range down to the 70 - 80% range were observed in two other demonstration precipitators operating with dry limestone injection systems. Additional information will be required to allow redesign or modification of precipitators to provide sufficient capacity to handle the increased loading. Flyash conditioning might also be explored as a means to overcome any adverse effects on flyash resistivity. The use of a baghouse as an alternative to an ESP would be advantageous for a new unit designed with limestone injection. Historically, SO_2

scrubber performance has not been affected by the addition of limestone to boiler flue gas provided that a particulate collection system is located prior to the scrubber.

Limestone Recycle

Due to the increased particulate loading during furnace injection and the tendency for overburning of limestone at elevated temperatures, recycle of limestone through the furnace does not appear attractive at this time. Use of a dry scrubber and possibly a bag filter may provide opportunities to recycle or re-use unreacted calcined limestone to achieve additional SO₂ removal. The injection of recycled material into a wet SO₂ scrubber may also be possible.

ASH FUSIBILITY TEMPERATURES AND OTHER SLAGGING/FOULING INDICES

Slag deposited on furnace waterwalls and convection surfaces is dependent on many ash variables including fusibility temperatures and the spread between the IT and FT (see below), base/acid ratio, iron/calcium ratio, silica/alumina ratio, sodium and acetic acid soluble alkali content and particle size.

Fusibility Temperature Measurements

Fusibility temperatures are an actual measurement under laboratory controlled condition showing the melting behavior of coal ash. It is perhaps the most basic means for predicting ash performance under furnace conditions. As measured by ASTM standards, four points are measured:

1. Initial deformation (IT)
2. Softening (ST)
3. Hemispherical (HT)
4. Fluid temperatures (FT)

The four points are illustrated in Figure 1.

Normally fusibility temperatures are reported as determined in a fuel-rich or reducing atmosphere. A reducing atmosphere is conventionally used to determine ash melting temperatures because it better represents conditions in the fire zone in the areas of the most intensive heat than does an oxidizing atmosphere, even under circumstances of firing with excess air because of the proximity of carbon around the mineral constituents in the char.

Fusibility temperatures determined in an oxidizing atmosphere reflect higher melting temperatures than determined under reducing conditions. Temperature differences will vary proportional to the amount of iron in the ash. As the amount of iron increases, the temperature differences in melting temperatures will increase. Iron compounds in the ferric state (+++) demonstrate higher melting temperatures than equivalent ferrous (++) compounds.

Table I lists reducing and oxidizing fusibility temperatures for both low and high iron ash and demonstrates the temperature differences resulting from the iron concentration.

Both the temperature levels and temperature spread between IT and FT are important in predicting ash behavior. For example, a lowered ash ST indicates a greater tendency for ash deposit buildup, whereas a wider IT-FT spread usually indicates greater ease of removal of the bulk of the deposit. As the IT-FT spread narrows the removal of deposits may become more difficult. In the laboratory ash fusibility studies described in this section we looked primarily at the effects of sorbents on ash fusibility temperatures by blending coal with sorbent (limestone), and ashing the mixture at 1400°F (760°C) in a reducing atmosphere.

The five coals utilized in this study are geographically and economically significant and range from high to low rank. Selected coals (Table II) included Midwestern bituminous, Eastern bituminous, Utah bituminous, Wyoming subbituminous and Texas lignite.

Base/Acid Ratio. The base/acid ratio has been empirically correlated with ash melting temperatures. While individual ash constituents (SiO_2 , Al_2O_3 and TiO_2) are usually considered high melting, ash fusion temperatures are lowered proportionally by the relative amounts of basic oxides available in the ash for reaction. Minimum melting points are generally associated with base/acid ratios between 0.4 and 0.7.

Silica/Alumina Ratio. According to the data obtained at C-E's Kreisinger Development Laboratory, under reducing atmospheres, no appreciable change in ash fusibility is noted for silica/alumina ratios in the range of 1.7 to 2.8. For decreasing ratios less than 1.7, the softening and fluid temperatures both increase; for ratios greater than 2.8, the fluid temperature decreases.

Iron/Calcium Ratio. The base/acid ratio does not account for differences in the fluxing and slagging behavior of ash deposits. Among the five basic ash components, iron and calcium are the most important. The combined fluxing effect of iron oxides and calcium oxide has a complex relation to the percentage of the two fluxes present. In general, this effect is most pronounced when the $\text{Fe}_2\text{O}_3/\text{CaO}$ ratios are between 3 and 0.3. Obviously, the absolute quantities in the ash and other ratios will also have a bearing on the ash behavior.

Active Alkali. Another major factor affecting convection section fouling properties of solid fuel ash is the sodium content. The ash deposit bonding strength usually increases as sodium content increases. The following facts apply as generally to Western low rank coals where the sodium is present in an organic form. Sodium levels associated with higher rank coals represent inorganic compounds and, as such, are less reactive.

% Soluble Na ₂ O in Ash (Equivalent Soluble ² Alkali in Ash)	Fouling Tendency
1.0	Low
1.0-2.0	Medium
3.0	High
5.0	Severe

Because of the relative ease of determination, the chloride content of coal is frequently used with Eastern coals as an indicator of the fouling potential of the active alkalies (sodium and potassium). American experience confirms that tightly bonded deposits in the convection passes can be expected when the inorganic chloride level in the coal exceeds 0.3 percent.

Experience has shown that measuring coal chloride alone does not account for all of the sodium or potassium; a more accurate procedure has been developed to determine acid soluble alkali directly.

Acetic acid-soluble alkali determinations together with gravity fractionation would permit a more refined assessment of the probability of selective ash deposition and consequently the slagging/fouling tendency of a coal ash. Acetic acid soluble alkali determinations made previously showed that the Wyoming subbituminous coal evaluated in this study has high convection section fouling tendencies. The Western bituminous coal was shown to be a moderate fouling coal while the remaining three coals have very low tendency for fouling.

Specific furnace behavior of a coal is contingent upon the total effect of such variables as combustion rates, flame temperatures, particle size, fuel/air ratios, particle residence time etc. on the extent of decomposition of coal minerals and their reformation into other compounds.

Each slagging and fouling index has its merits in understanding and predicting ash behavior, however, the limitations of any one or combination of indices must be recognized. Even though inconsistencies may arise these indices can still be used to identify trends in ash behavior during coal firing.

Ash Fusion Test Results

In most of these studies the selected coal and sorbent were mixed prior to ashing under reducing conditions at 1450°F (788°C) for Ca/S ratios of 0, 0.5, 1, 2 and 4. Conventional ASTM cone fusion determinations were made on each mixture in a temperature controlled muffle furnace under reducing conditions. These procedures most nearly simulate the localized conditions conducive to slagging and/or fouling in a boiler into which an SO₂ sorbent has been injected at the burner zone. The results are shown in Figures 2 through 6 and summarized below.

Coal and limestone were also ashed separately, prior to mixing, to simulate alternate injection points in various furnace regions.

Midwestern Bituminous Coal. Ash fusion behavior with this coal ash follows a typical eutectic curve showing a minimum point in all four measured points at a Ca/S ratio of 0.5. Additions of limestone beyond a Ca/S of 1 resulted in a marked increase in fusion temperature (up to 2700°F, 1482°C) at Ca/S=2.

Following an initial increase in deposit buildup, with increasing Ca/S ratio, both deposit buildup and slagging potential should be reduced when limestone injection is used while firing this coal as deposits become higher melting and thus, drier. The total quantity of ash for removal would be increased as much as three-fold with increasing sorbent stoichiometric ratios.

Review of other indices shows that both the base/acid ratio and the iron/calcium ratio predict an initial significant slagging potential followed by a decrease with increasing calcium content (Table III).

Eastern Bituminous Coal. Ash fusibilities decreased sharply from a range of 2550-2700°F (1399-1482°C) for the coal alone to 2300-2425°F (1260-1329°C) at 1:1 Ca/S ratio. As additive stoichiometry was increased up to 4:1, the ash fusion range gradually leveled off to 2175-2225°F (1190-1218°C) range. While this change does not signal a change from dry to wet furnace operation, the potential for slagging would definitely be increased.

Only the iron/calcium ratio falls into a range which indicates an increase in slagging and fouling potential. As indicated by this change the additional limestone fluxes with the iron resulting in a significantly lower ash fusion range (Table III).

Utah High Volatile Bituminous B Coal. The fusion temperature dropped by more than 300°F (149°C) as the Ca/S ratio reached 1.0, while the initial deformation temperature was reduced by only 100°F (38°C); thus indicating an increase in slagging potential but only a slight change in fouling. As Ca/S increased to 4.0, no additional change was observed. Removal of deposits might be expected to become somewhat more difficult as the IT-FT spread narrowed.

While the iron/calcium ratio of the coal suggests a slightly positive slagging potential, increasing amounts of sorbent have the effect of decreasing the potential for slagging and fouling as predicted by all other indices (Table III).

Wyoming Subbituminous Coal. Addition of limestone to this coal resulted in a continuing increase in fusion temperature (2150 to 2700°F 1177 to 1482°C) so that little or no deposit buildup should be anticipated after

the Ca/S ratio reaches 2. Any buildup of deposit in the superheater or reheater sections as a result of increased ash loading should be readily removable by existing sootblowers.

Unfavorable initial base/acid and iron/calcium ratios on the coal show improvement with addition of limestone thus supporting the continuing improvement in measured ash fusion (Table II).

Texas Lignite. With this coal the FT dropped by about 150°F (83°C) as the Ca/S ratio reached 1.0 while IT showed almost no change. Very little increase in deposit buildup and slagging potential is indicated although deposit removal might be somewhat more difficult since the IT-FT spread is narrowed with increasing calcium.

The other indices suggest a slight improvement in overall slagging potential as the Ca/S ratio is increased (Table III).

Similar studies were conducted utilizing both dolomite ($\text{CaCO}_3 \cdot \text{MgCO}_3$) and magnesite (MgCO_3) as sorbents. The same trends in ash fusibility were observed as with limestone. These results were not included in this paper since limestone is more readily available and generally more economical.

Summary of Laboratory Ash Fusion Tests

Based on the laboratory ash fusion studies, all coals tested except the Wyoming subbituminous showed an increase in slagging potential with addition of limestone until the Ca/S ratio exceeded 1. The exact relationship between fusion properties and fouling has not been established. Ash fusion behavior of the Utah and Texas coals was not affected by increased limestone beyond this point, while the Midwestern bituminous coal exhibited a marked increase in fusion temperature to 2700°F, (1482°C), and thus reduced slagging potential at a Ca/S ratio of 2. The Eastern bituminous coal ash fusion temperature continued to decrease gradually to 2250°F (1232°C) at a Ca/S ratio of 4 with a corresponding increased potential for deposit buildup. The Wyoming subbituminous coal showed a continuing increase in fusion temperature (2150 to 2700°F, 1177-1482°C) by the time the Ca/S ratio reached 2. Thus, the tendency of deposit buildup with this coal might be expected to decrease at all levels of limestone addition.

Increased slagging potential, as indicated by a decrease in initial deformation temperature during the ash fusion determinations, occurred with all three bituminous coals. IT values for the Eastern and Western coals plateaued at Ca/S ratios between 1 and 2, while for the Midwestern coal there is a leveling off when the Ca/S ratio exceeded 0.5 followed a marked increase from Ca/S ratio of 1 to 4. The Wyoming subbituminous coal ash showed a decrease in slagging potential with increasing Ca Content while Texas lignite ash remained unaffected up to a Ca/S ratio of 4.

The fouling effects on high sodium coals may be significantly reduced by dilution with increased calcium content during limestone addition. Increased slagging potential, as indicated by a decrease in initial deformation temperature during the ash fusion determinations, occurred with all three bituminous coals. IT values for the Eastern and Western coals plateaued at Ca/S ratios between 1 and 2, while for the Midwestern coal there is a leveling off when the Ca/S ratio exceeded 0.5 followed by a marked increase from Ca/S ratio of 1 to 4. After the Ca/S ratio exceeds 1 the Fe/Ca ratio is also out of the slagging range. The Wyoming subbituminous coal ash showed a decrease in slagging potential with increasing Ca content while Texas lignite ash remained unaffected up to a Ca/S ratio of 4.

Thus it can be seen that limestone added to a boiler for SO₂ removal may affect the ash behavior of different coals in varying manners. Whether or not a fouling or slagging problem will occur with Limestone Injection (LIME) firing depends on the actual fusibility temperature of accumulated deposits as well as on the design and operation of a particular boiler.

For example the fusibility curves for both the Eastern and Utah coals suggest increased slagging and fouling potential. The ash fusibility temperatures of both coals are rather high initially and neither coal ash reached a dangerously low fusibility range in these tests. However, in practice the Eastern coal ash without limestone addition causes fouling problems probably due to selective depositions while the Utah coal is less troublesome.

Prior to actual injection of limestone into an operating boiler additional fusibility studies using actual ash deposits plus limestone would be recommended.

While bench scale testing provides a certain level of confidence pilot scale testing may better simulate actual furnace conditions due to selective deposition and complex interreaction of deposits at the higher heating rates of an operating boiler.

ENGINEERING AND OPERATIONAL FEASIBILITY

The objectives of this task were to evaluate the engineering and operational feasibility and plant reliability impact of sorbent injection on a new and retrofit basis for utility steam generators.

The first step in accomplishing these objectives was to generate a list of desirable and, by inference, undesirable attributes for sorbent injection, as determined in Task 1, applicable to a current utility steam generator. Then, using this list, a unit was chosen that would typify the design of units that were constructed during the 1970's.

Based on information contained in the background survey the areas of main concern in plant design that were looked at in the case study and that should be addressed in any limestone furnace injection application are:

- The availability of an area at the plant site where the limestone could be stored and prepared prior to injection.
- Sufficient quantities of sorbent available near the proposed plant to preclude unreasonable material handling costs.
- Flue gas particulate removal and conveying equipment with capacity to handle increased dust loading.
- Slagging and fouling tendencies of the parent coal and the anticipated tendencies with the addition of limestone as compared to the ash fusion test results reported in task 2.
- Locations and coverage of soot blowing equipment.
- Convective pass design capable of handling the increased dust loading without excessive plugging.
- Low NO_x firing capacity or some form of furnace gas temperature control to limit overburning of the limestone.

The unit chosen for case study, a modern 500 MWe single-furnace boiler, was neither a best case nor a worst case application for the limestone injection program. This boiler exhibited many of the design characteristics advantageous for limestone injection but still would require some boiler modifications and thus would yield a more realistic economic evaluation. The advantages that the selected unit possessed include overfire air firing capabilities, minimal slagging tendencies, and the availability of both high and low sulfur coal and limestone. The major disadvantage was the convective pass tubing layout, including a staggered-spiral finned economizer. Pertinent information on the furnace and firing system is shown below.

Retrofit Case Study

Boiler type	- Tilting Tangential, Controlled Circulation [®] , radiant reheat
Generator rating	- 500 MW
Steam flow @ rated capacity	- 3,800,000 lb/hr
Operating pressure	- 2620 psig

Retrofit Case Study (Cont'd.)

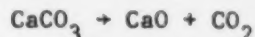
Air temp. to windbox	- 575°F
Furnace width/furnace depth	- 56'-2 ¹ / ₂ "/49'-3 ³ / ₁₆ "
Pulverizers	- Six RP bowl mills
Particulate collector	- Hot ESP ahead of air preheater

In order to fully understand the implications of steam generator design and operation and also the economics associated with sorbent injection for sulfur emissions control, it was decided to use the two coals that are available at this plant for the study. Analysis of these two coals, the 0.6% sulfur Low-S coal and the 3.4% sulfur High-S is shown in Table IV.

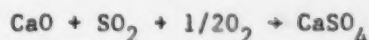
In order to design the sorbent injection system and to calculate the amounts of sorbent required, certain assumptions were made. These assumptions are necessary due to insufficient background information in determining the effect of furnace sorbent injection for sulfur emissions control. The following are the assumptions made in calculating the required sorbent amounts.

- A. A 50% sulfur compounds removal efficiency from uncontrolled stack emissions, this assumption was required to determine the amount of extra coal required due to the heat of formation of CaSO_4 , and to determine the weight and composition of the products of reaction (sludge).
- B. A low- NO_x firing system is necessary to lower the peak flame temperature by staging the fuel burning process.
- C. The SO_2 removal efficiency will vary depending on such variables as peak flame temperature, sulfur and mineral content in the coal, method of coal firing, boiler configuration, limestone reactivity CaCO_3 fineness, injection scheme and Ca/S ratio. The dominating effect or effects and their influences has yet to be determined. Therefore, this study has chosen to use: (1), four different calcium to sulfur ratios (1:1, 2:1, 3:1, 4:1) for both coals; (2), a CaCO_3 fineness of 90% passing through 325 mesh; and (3), injection of the CaCO_3 with the coal to optimize mixing.
- D. All the calcium carbonate (CaCO_3) which is injected into the boiler will calcine to calcium oxide (CaO) and carbon dioxide (CO_2).
- E. The following chemical reactions occur during the absorption of sulfur dioxide when using calcium carbonate.

(i) Calcination



(ii) Absorption of Sulfur



Injection System

It is currently felt that the best way to achieve the four injection system criteria presented in the background survey would be to inject the limestone into the boiler at the windbox elevation, in conjunction with a low-NO_x system, which will lower the maximum flame temperature and thus, limit the deadburning of limestone. It was decided that the limestone would be injected through the coal nozzles for several reasons: first, to maximize both the residence time in the critical temperature region, second, to maximize the mixing between the coal and the limestone particles, and third, to minimize capital costs for the system by using existing nozzles and thus, not modifying pressure parts in the boiler.

Therefore, using these criteria, a sorbent handling, pulverizing and injection system was designed. The entire system is made up of commercially available components and appropriate selections of the components have been made for the two coal types and four sorbent-to-sulfur ratios used in this study. See Figure 7 for a typical flow schematic of the injection system.

Reviewing the basic description of the system, we have a limestone storage site set up near the coal site at the plant. A vibrating conveyor transports the limestone inside the enclosure to a bucket elevator, which in turn feeds raw limestone silos. The limestone is pulverized and then distributed to surge silos. Pneumatic screw pumps allow the limestone to flow to a fuel distributor which transports the material to the outlet piping of the coal pulverizer. The pulverized limestone is premixed with the pulverized coal and injected into the furnace.

Boiler Performance with Sorbent Injection

Slagging and Fouling - Based on the laboratory ash fusion studies, the slagging and fouling tendencies of the High-Sulfur (High-S) coal (Midwestern bituminous) would decrease for the sorbent-to-sulfur levels studied. For the Low-Sulfur (Low-S) coal (Eastern bituminous) the slagging and fouling tendencies would increase. However, the chosen unit was designed for the High-S coal which has lower ash fusion temperatures in the baseline case (no sorbent added) than the Eastern bituminous in the worst case (4:1 sorbent-to-sulfur ratio). Thus, slagging and fouling tendencies with sorbent injection should be less than the boiler design conditions.

Erosion of rear pass heat transfer surfaces is not expected to be a problem. However, the magnitude of dust (up to 16 lb/MBtu for the Low-S coal and up to

60 lb/MBtu for the High-S coal) generated will require a streamlined gas path to prevent plugging. Also, increased sootblower coverage is recommended for the economizer section. In the case study, this streamlining was done by modifying the economizer section.

From the background survey it appears that some modification must be made to the precipitator in order to handle both the increased loading and the decrease in efficiency caused by the limestone. Unfortunately there is no conclusive data that gives us a clear indication of how much of a modification must be done.

However, the ESP of the case study unit was designed for a high ash content coal (inlet dust loading of up to 5 grains/ACFM) and therefore can handle the increased loading for all sorbent stoichiometries with the Low-S coal (at a 4:1 calcium to sulfur ratio the inlet dust loading is 3.0 grains/ACFM). With the High-S coal the precipitator would have to be enlarged just to accommodate the increased particulate loading with any addition of sorbent.

To accommodate the increased particulate loading it would be possible to incorporate a fabric filter baghouse downstream of the air preheater. The cost would be the same or less than a second electrostatic precipitator and the baghouse would not be subject to any decrease in efficiency due to higher resistivities. It would also be easier to install than a precipitator.

In the case of a new unit design one fabric filter could be sized based on the total gas volume and would be independent of the level of particulate loading.

Because of the injection of limestone into the furnace, all ash hoppers will experience a higher loading. In general, ash hoppers are oversized to a great degree so it is assumed that no modifications to compensate for additional ash are necessary although the operational frequency of the sluice systems will have to be increased.

ECONOMIC EVALUATION

The objective of this task was to evaluate economically the application of limestone injection to a nominal 500-MW (electric) utility boiler for both a retrofit and new unit design. For retrofit applications, estimated costs include modifications to existing hardware and installation of new equipment. Operation and maintenance costs associated with limestone injection have been qualitatively assessed within 20%.

Costs were developed for eight different cases for both new and retrofit applications consisting of four separate sorbent stoichiometries and two coals. Costs were also developed for the addition of a baghouse, but were not included in the total or leveled costs due to the lack of quantitative information available to determine the effect of limestone addition on precipitator efficiency.

Cost of the Limestone Injection System

In this section the limestone system proposed in the engineering evaluation has been sized for capital costs. Current costs have been secured from manufacturers for all major items of the limestone injection system. Included in the total capital cost are all the storage, handling, and injection equipment, controls, structural steel, building enclosure, and construction labor. Costs for limestone delivery facilities (e.g. new rail sidings, roadways, etc.) have not been included.

All eight cases have been costed separately. The following is the total process capital required for each case:

<u>Coal</u>	<u>Ca:S</u>	<u>Process Capital Cost for</u> <u>the Limestone Injection System</u>
		(\$ x 10 ⁶)
Low-S	1:1	\$2.37
Low-S	2:1	\$2.8
Low-S	3:1	\$3.2
Low-S	4:1	\$4.1
High-S	1:1	\$3.3
High-S	2:1	\$4.1
High-S	3:1	\$5.0
High-S	4:1	\$6.6

The costs of the limestone injection system would be identical for both a retrofit and new unit design assuming that for a retrofit application that space is available for the equipment.

Cost Evaluation of the Economizer Modification

The selected unit presently has a staggered spiral-finned economizer. This arrangement provides additional heat surface but reduces the free area normal to the gas flow. With the injection of limestone, this economizer would not be acceptable, so a retrofit design must be incorporated. This modification should allow free flow of the increased flyash due to limestone injection and also lessen the potential erosion problem. The ideal modification in this case would be a bare-tube arrangement, but is impossible because of the limited space in the back-end of the boiler. The cost of a modification of this type has been estimated at approximately \$1.9 million.

We have assumed that no additional costs would be incurred in a new unit design. This is because new units are generally designed for a wider fuel property range and use bare tube in-line economizers.

Cost Evaluation of the Low NO_x Firing System

The low NO_x firing system that would be installed is the C-E Low NO_x Concentric Firing System (LNCFS). This system would reduce peak temperatures in the furnace and limit deadburning of the limestone, creating greater reactivity and higher sulfur removal.

The cost of an LNCFS retrofit design for a 500-MW boiler is approximately \$1/KW.

On a new unit, the additional process capital required for a low NO_x firing system versus a standard windbox design could range between \$0.1/kW^x and \$5.5/kW depending on the system selected and the coal type.

Total Costs

The basic format for the final cost estimates was taken from EPRI's, "Economic Premises for Electric Power Generating Plants," June 1, 1981, which allows the reader to apply the economic analysis to his particular situation. Costs have been broken down into the following categories and sub-categories:

I Capital Investment

- A. Plant investment process capital; facilities, engineering and office fees, contingencies, and escalation factors
- B. Preproduction costs (to cover extra costs during start-up due to inefficiencies)
- C. Inventory Capital (to account for consumables in stock or storage)

II Fixed and Variable Operating and Maintenance Costs

- A. Fixed operating costs (including fixed operating and maintenance labor costs and maintenance material and overhead charges)
- B. Variable operating costs (including variable operating and maintenance labor costs and variable maintenance material and overhead charges)
- C. Consumable operating costs (including the sorbent cost and additional waste disposal charges)

All variable and consumable operating costs were then adjusted by the capacity factor for the subject unit: 65% of design full load. Following this, all costs, including variable, consumable and fixed operating costs and investment capital, were levelized such that a single value would be used to represent the varying revenue requirements over the 30-year life expectancy of the system.

Functions were developed showing the relationship between the calcium:sulfur ratio and the levelized busbar power cost for both new and retrofit applications (Figure 8). Functions relating the calcium:sulfur ratio to the levelized fixed charges and to the levelized consumable operating costs were also developed. However, we have included only the latter (Figure 9) to show that the predominant factor affecting the busbar power cost of the sorbent injection system is the cost of the sorbent and the disposal of reacted wastes. Total capital requirements including process capital, contingencies for both the project and the process, and engineering and start-up costs range between \$7/KW and \$25/KW for a new unit and between \$14/KW and \$32/KW for a retrofit application. The capital requirements and how they relate to the Ca:S ratio are shown in Figure 10. Also, as shown in Figure 11, as the calcium to sulfur ratio is increased the cost of an injection system becomes more and more dependent on the sulfur level in the coal.

CONCLUSIONS

1. The background information survey provided a substantial data base to design and evaluate a SO_2 sorbent injection system. Sorbent types, handling and injection systems and many of the effects of sorbent injection on boiler performance were evaluated with a high degree of confidence. However, there are still several areas of informational voids which should be filled before this technology is commercialized. Major issues of concern that were not acceptably dealt with in the reviewed literature include:
 - the time/temperature history requirements of the limestone/sulfur reaction necessary to achieve high SO_2 removal
 - the time/temperature history of a boiler operated under low NO_x operations
 - sulfur removal efficiency of limestone as a function of total sulfur content
 - the optimum Ca:S ratio for efficient sulfur removal
 - limestone injections effects on precipitator performance and efficiency
2. The ash fusion tests conducted during this program have further verified that the fusibility of a particular coal ash is dependent

on all of its constituents and not just one of its components such as limestone.

3. The engineering and operational analysis determined that furnace limestone injection for SO_2 removal is technologically feasible and that an injection system can be fabricated using commercially available equipment. It should be noted that retrofit application of this technology should be looked at in a site-by-site basis. In particular, space requirements, sorbent availability, particulate removal and disposal equipment capacity, slagging and fouling tendencies, and the effects of increased dust loading on convective surfaces are items which could pose major problems if not addressed properly.
4. The capital costs for a retrofit application of this technology range between \$14/kW for low sulfur coals and \$32/kW for high sulfur coals. For new units these costs range between \$7/kW and \$25/kW for low and high sulfur coals respectively. Consumable expenditures, including the raw limestone cost and the increased waste disposal cost, represent the major operating expense for this system (38% for a 1:1 Ca:S ratio with the low-S coal and 91% for 4:1 Ca:S ratio with the high-S coal). The levelized busbar power costs of a low sulfur coal sorbent injection system range between 1.1 and 2.7 mills/kWh, for a high sulfur coal the range is 3.9 to 13.8 mills/kWh. New and retrofit applications are within 19% of each other.

To put some perspective on these costs a recent evaluation by EPRI on FGD wet scrubber technologies has estimated the capital and levelized revenue requirements at between \$100/kW and \$200/kW and between 7 mills/kWh and 16 mills/kWh respectively. The difference in cost between the Low-S coal and the High-S coal (current delivered prices \$57/ton and \$26/ton respectively) analyzed in this study represents a 31 mills/kWh cost differential on a 30-year levelized basis.

RESEARCH RECOMMENDATIONS

Before this type of system is offered as a commercial option to, or to be used in conjunction with, tail-end FGD systems, more research and developmental work will be required to more clearly define the busbar power costs. This economic analysis has determined that further study, pilot scale tests, and demonstration tests would be justified in the following areas.

1. Relating the efficiency of limestone as a sulfur adsorbent to variables such as total sulfur content and/or calcium-to-sulfur ratio. This research should more quantitatively define the limestone costs, which presently range between \$0.7 million and \$1.4 million per year for the low sulfur coal and between \$4.5 million and \$9.0 million per year for the high sulfur coal.

2. Ash removal and waste byproduct systems. For example, waste disposal charges can be halved when using a dry ash removal system versus a wet system. This could lead to a 25% reduction in the consumable operating costs for a limestone injection system.
3. Particulate removal system. If modifications to the particulate removal system are required on a retrofit application this could significantly increase the capital costs of this design and add approximately 1.25 mills/kWh to the busbar power cost. Particular interest should be placed on the effects of particulate resistivity and flue gas conditioning on precipitator performance.
4. Optimization of solid fuel burners and boiler design to increase the efficiency of sulfur absorption with limestone injection.

One impetus for recommended research is the cost differential between high and low sulfur coals, 31 dollars/ton for the coals studied in this project, Low-Sulfur with 0.6% S currently has a delivered price of \$57/ton and High-Sulfur with 3.4% S has a price of \$26/ton. With this differential, the computed savings in fuel costs could amount to as much as 32 mills/kWh on a 30 year levelized basis for a utility with a nominal generating capacity of 500 MW and a capacity factor of 65%.

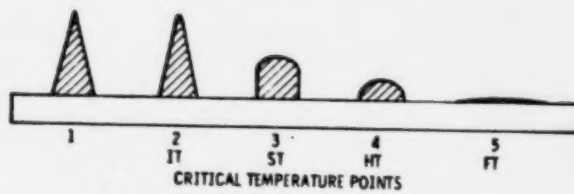
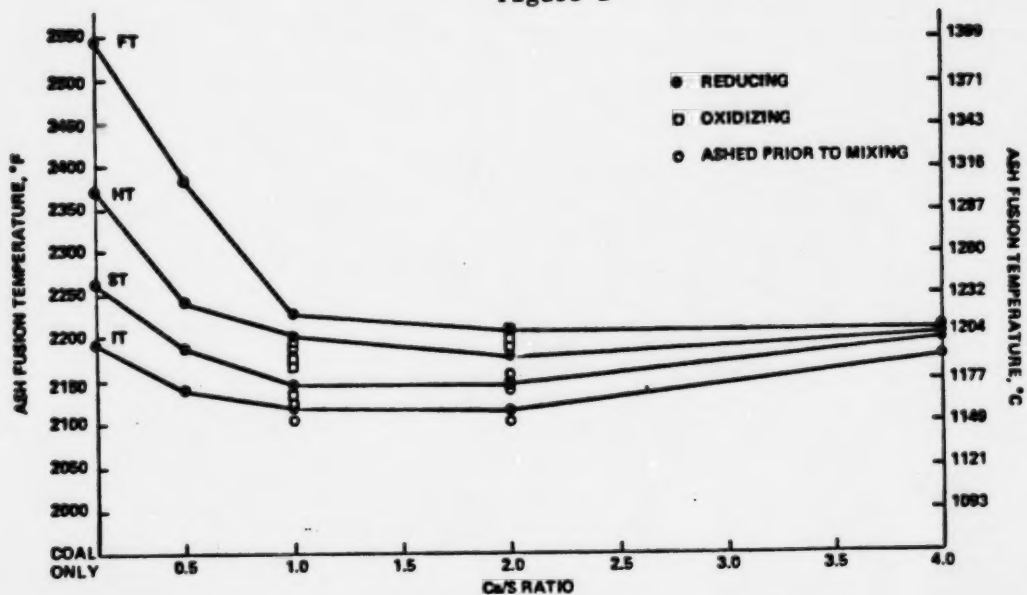


Figure 1
 Critical Temperature Points

- | | | |
|----|------------|---|
| 2. | IT (Or ID) | Initial Deformation Temperature |
| 3. | ST | Softening Temperature ($H = W$) |
| 4. | HT | Hemispherical Temperature ($H = 1/2 W$) |
| 5. | FT | Fluid Temperature |

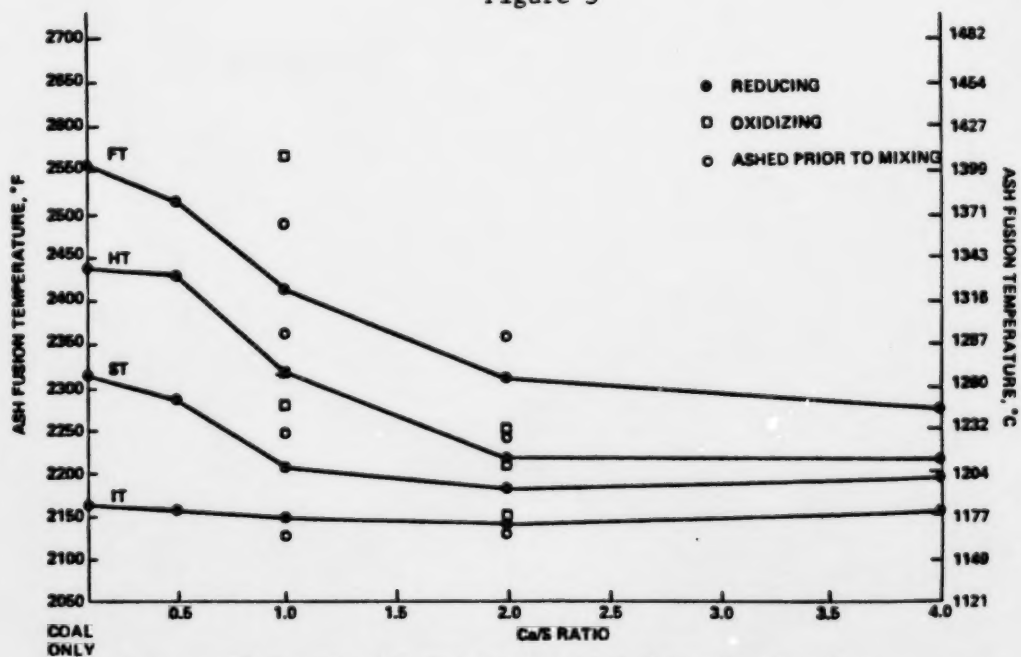
SERIES I LABORATORY ASH FUSION DETERMINATIONS (WITH LIMESTONE)
UTAH HI VOLATILE B COAL

Figure 2



SERIES I LABORATORY ASH FUSION DETERMINATIONS (WITH LIMESTONE)
TEXAS LIGNITE

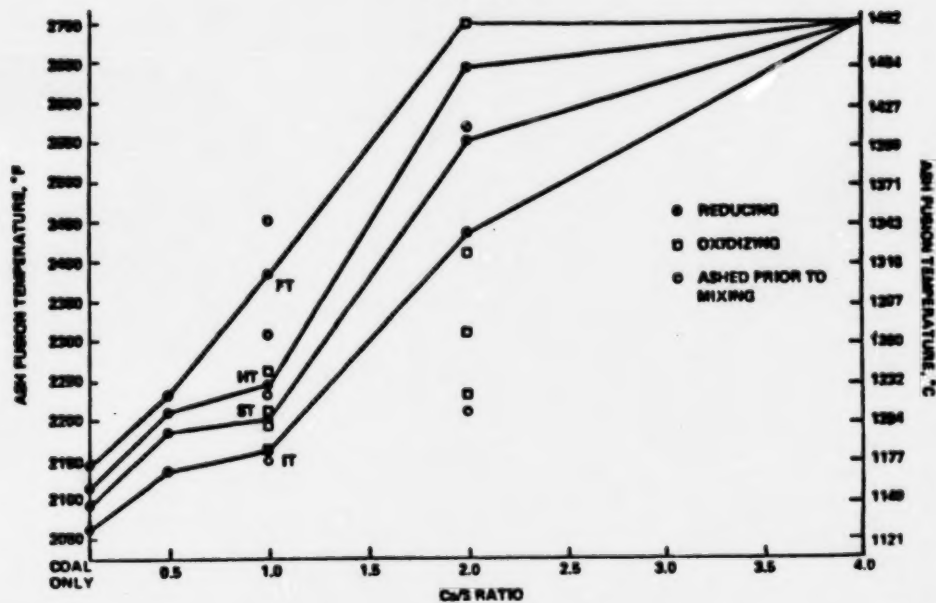
Figure 3



Figures 2-6. Series I Laboratory Ash Fusion Results
Sorbent Type: Limestone
Sorbent-to-Sulfur Ratio Range: 0-4:1

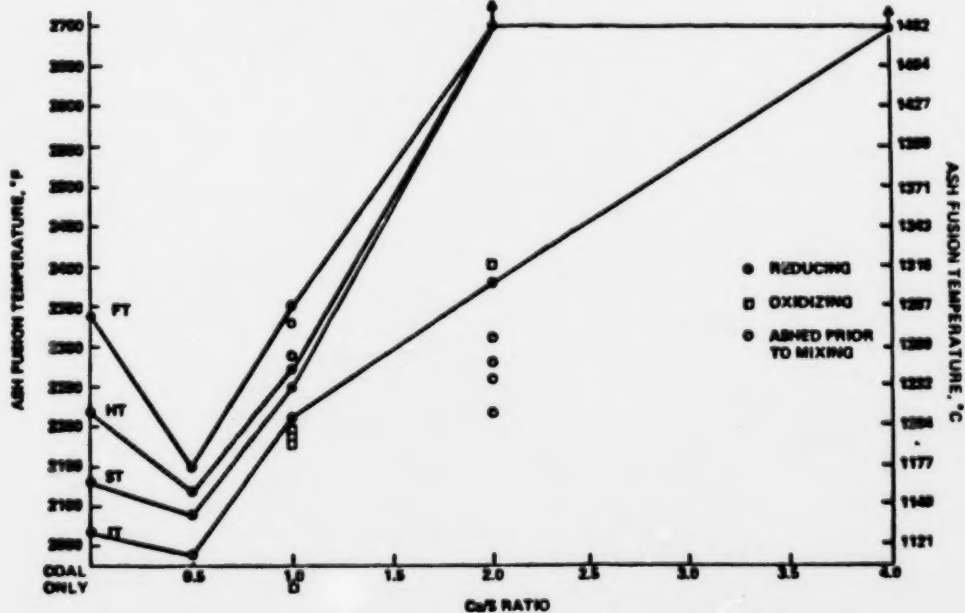
SERIES I LABORATORY ASH FUSION DETERMINATIONS (WITH LIMESTONE)
WYOMING SUB-BITUMINOUS C

Figure 4



SERIES I LABORATORY ASH FUSION DETERMINATIONS (WITH LIMESTONE)
MIDWESTERN BITUMINOUS

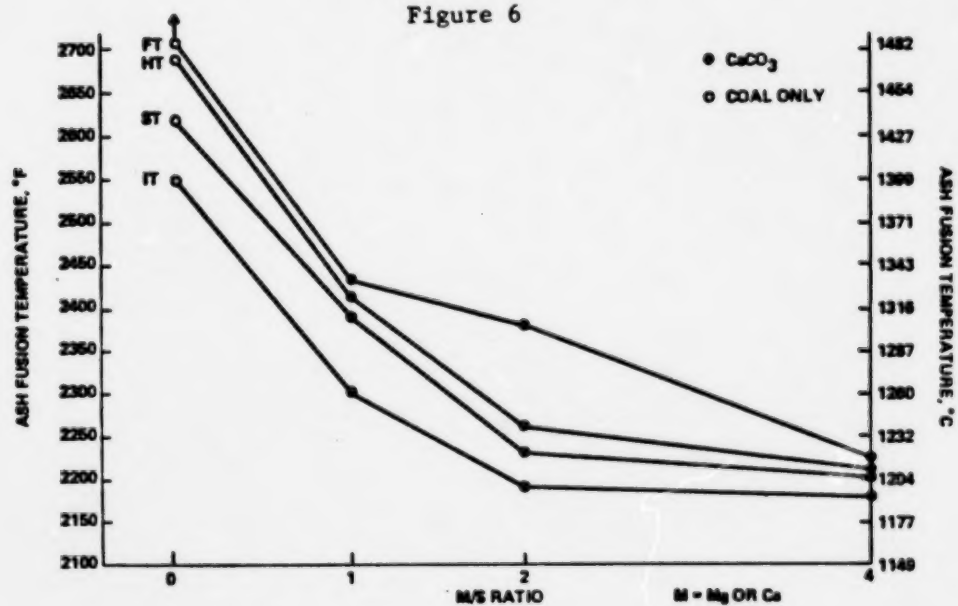
Figure 5



Figures 2-6. Series I Laboratory Ash Fusion Results
Sorbent Type: Limestone
Sorbent-to-Sulfur Ratio Range: 0-4:1

SERIES I LABORATORY ASH FUSION DETERMINATIONS (WITH LIMESTONE)
EASTERN BITUMINOUS

Figure 6



Figures 2-6. Series I Laboratory Ash Fusion Results
Sorbent Type: Limestone
Sorbent-to-Sulfur Ratio Range: 0-4:1

- LEGEND:
- ①- FILTER
 - ②- MANUAL SHUT-OFF VALVE
 - ③- AUTOMATIC VALVE
 - ④- MOTOR
 - ⑤- SPEED SWITCH LOW
 - ⑥- SPEED SWITCH HIGH
 - ⑦- SPEED MOTOR CONTROLLER
 - ⑧- DIFFERENTIAL PRESSURE SWITCH LOW
 - ⑨- DIFFERENTIAL PRESSURE SWITCH HIGH
 - ⑩- DIFFERENTIAL PRESSURE SWITCH NORMAL
 - ⑪- LEVEL SWITCH LOW
 - ⑫- LEVEL SWITCH HIGH
 - ⑬- LEVEL SWITCH NORMAL

WELL
SECTION FOR AUTOMATIC CONTROL

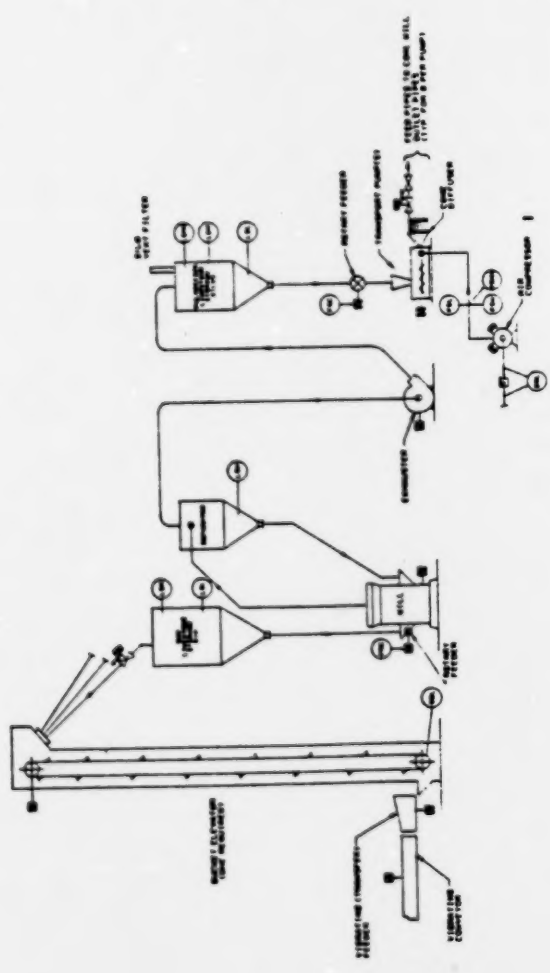


FIGURE 7
Flow Schematic-Limestone
Injection System

LEVELIZED POWER COST AT 65% CAPACITY FACTOR

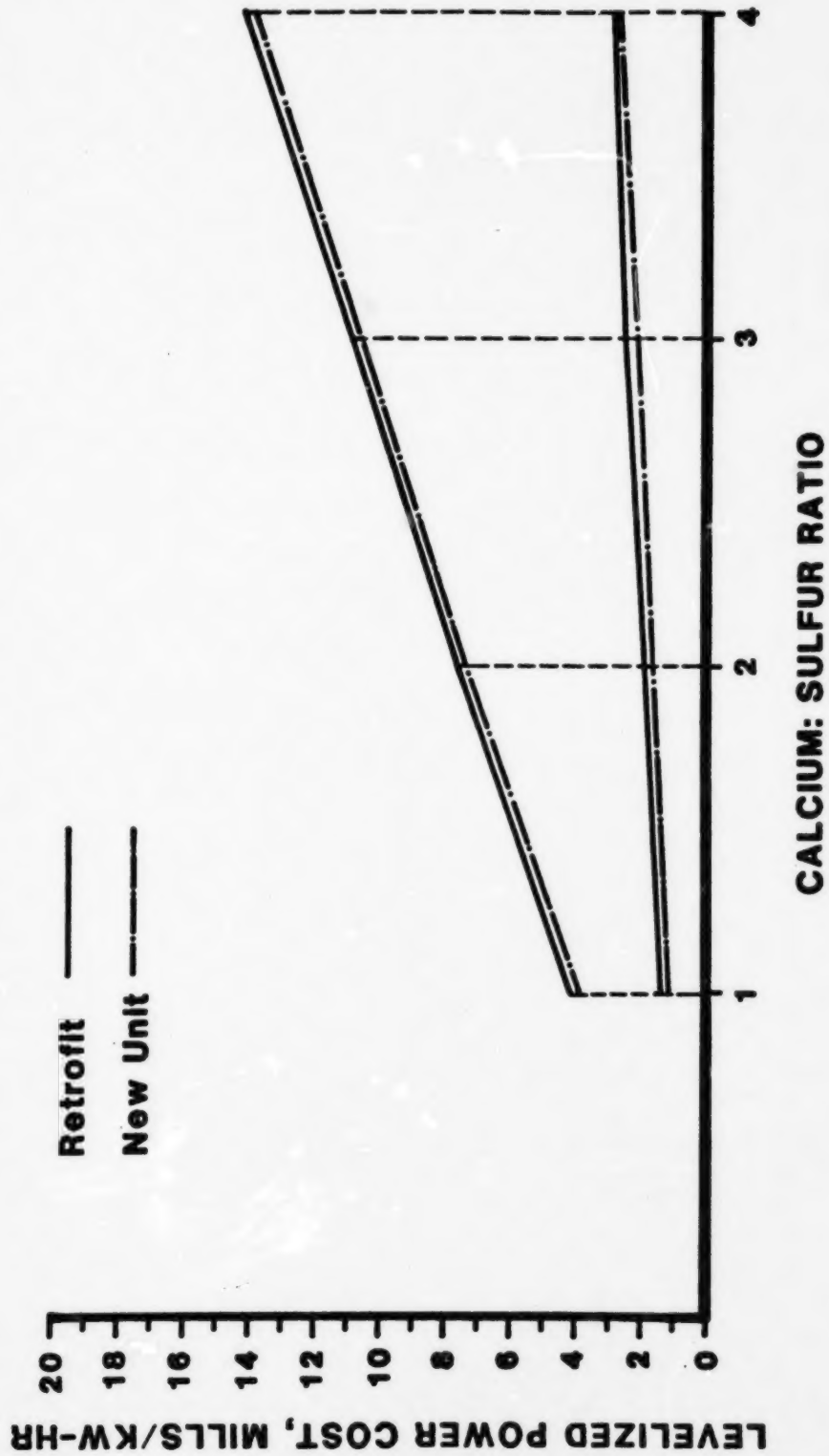


Figure 8. Levelized Power Cost at 65% Capacity Factor

LEVELIZED CONSUMABLE OPERATING COST

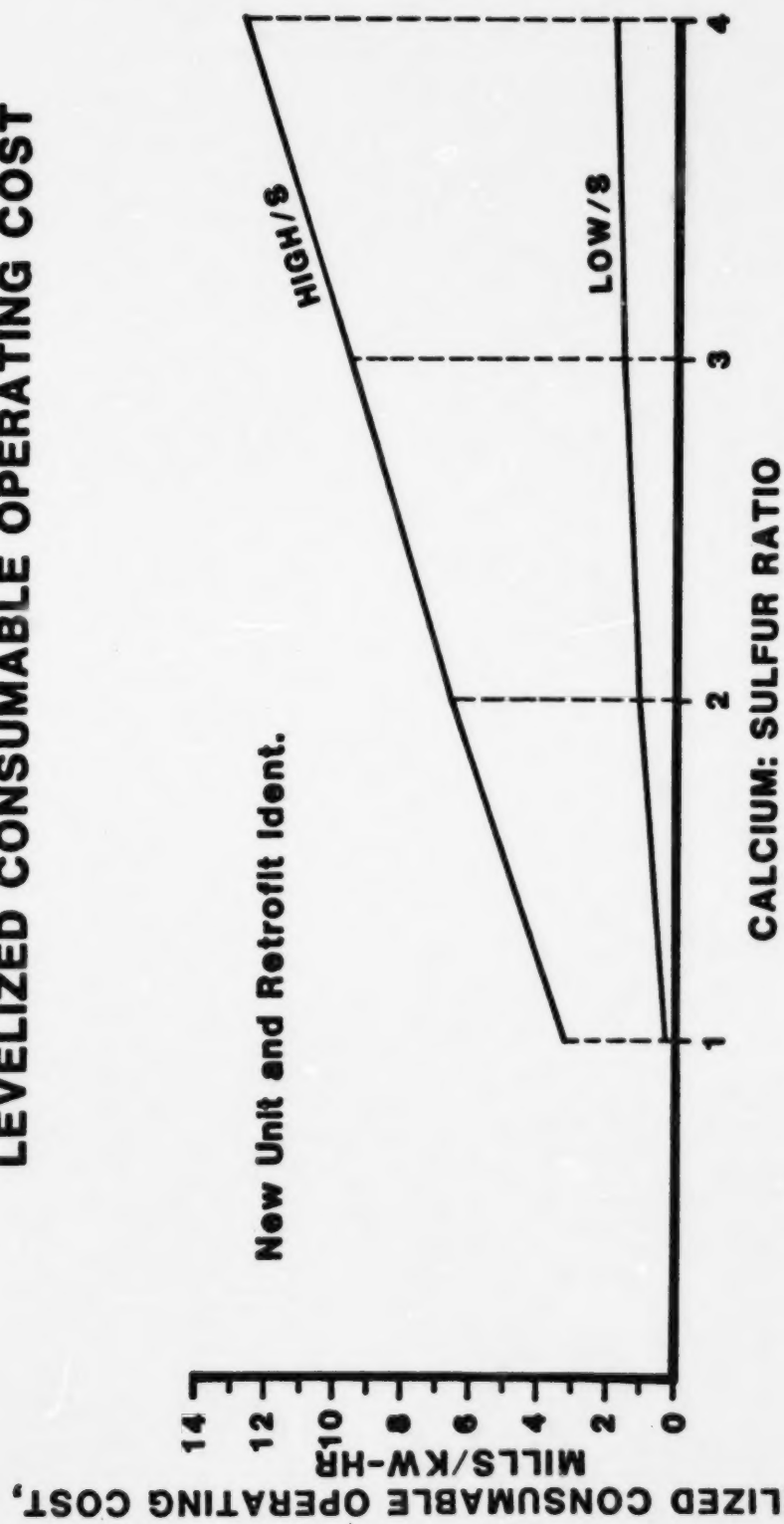


Figure 9. Levelized Consumable Operating Cost

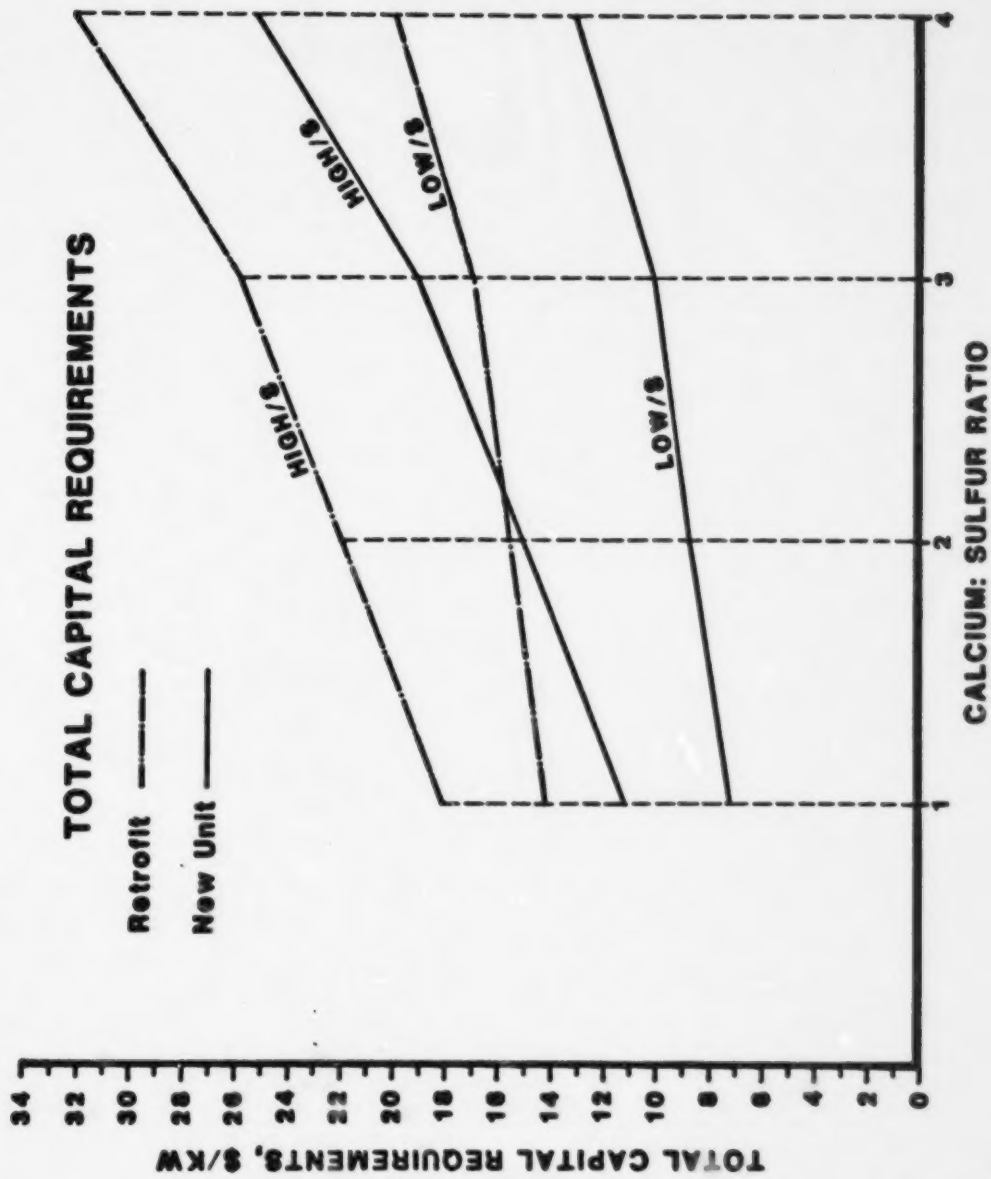


Figure 10. Total Capital Requirement

30 YEAR LEVELIZED POWER COST

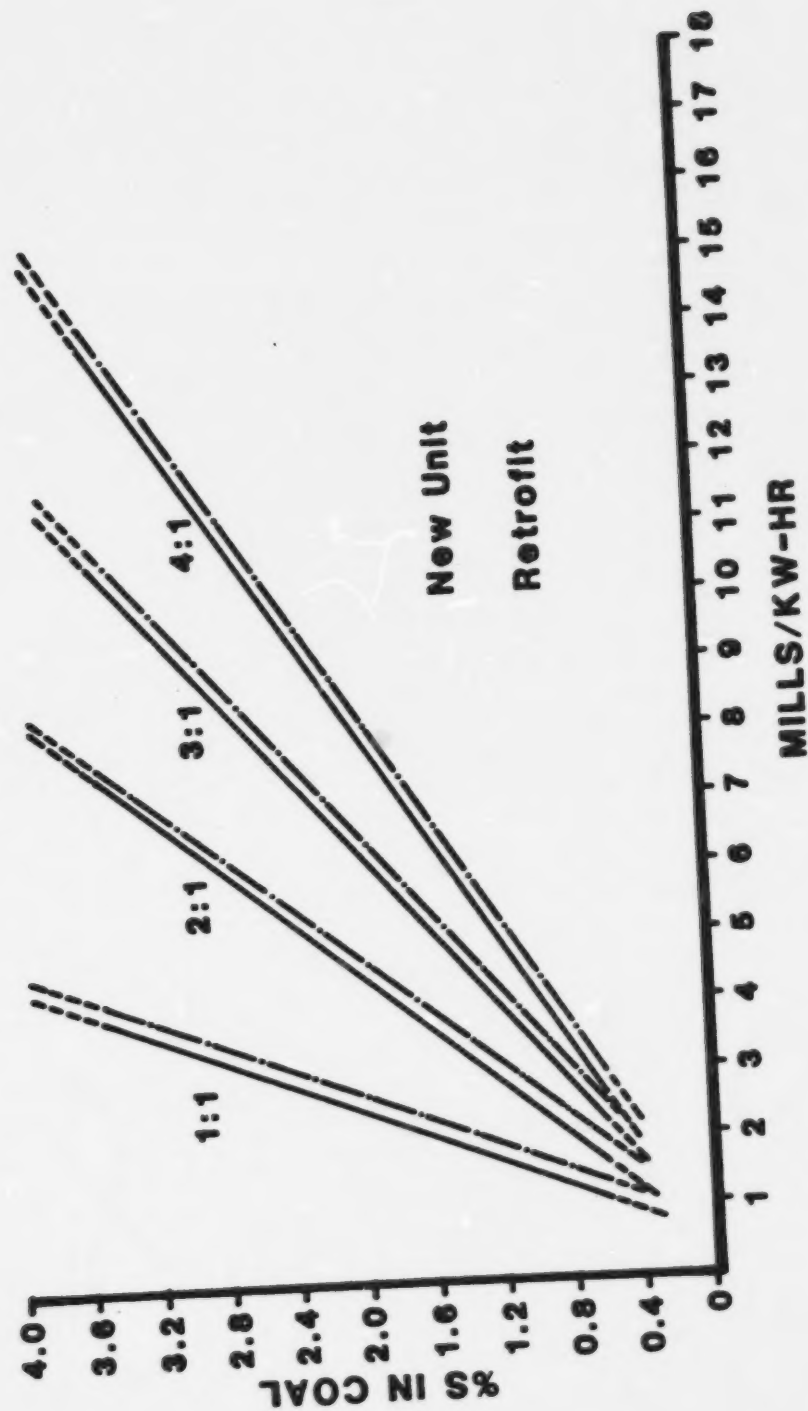


Figure 11. 30 Year Levelized Power Cost

TABLE I: ASH FUSIBILITY TEMPERATURES
Reducing Vs. Oxidizing Atmosphere

Atm.	Fusibility Temp., °C	High Iron		Low Iron	
		Reducing	Oxidizing ΔT	Reducing	Oxidizing ΔT
I.T.		1130	1235	1170	1205
S.T.		1155	1255	1200	1225
F.T.		1240	1295	1270	1315
					35
					25
					45
Ash Comp.					
SiO ₂			31.9		41.8
Al ₂ O ₃			17.2		17.2
Fe ₂ O ₃			17.5		6.5
CaO			10.8		11.5
MgO			4.7		4.5
Na ₂ O			0.3		0.4
K ₂ O			0.6		0.6
TiO ₂			0.5		0.7
P ₂ O ₅			0.1		0.3

TABLE II

COAL ANALYSES

COAL SOURCE	MIDWESTERN BITUMINOUS		EASTERN BITUMINOUS		UTAH BITUMINOUS		WYOMING SUBBITUMINOUS		TEXAS LIGNITE	
	AS RECEIVED	AS RECEIVED	AS RECEIVED	AS RECEIVED	AS RECEIVED	AS RECEIVED	AS RECEIVED	AS RECEIVED	AS RECEIVED	AS RECEIVED
PROXIMATE, WT. PERCENT										
MOISTURE (TOTAL)	1.9	1.3	2.5	9.2	24.7					
VOLATILE MATTER	40.6	32.2	42.2	44.8	39.5					
FIXED CARBON (DIFF)	45.9	52.5	45.8	40.8	17.1					
ASH	11.6	14.0	9.5	5.2	18.7					
TOTAL	100.0	100.0	100.0	100.0	100.0					
HHV, BTU/LB (kJ/kg)	11530.(26,856)	12600.(29,358)	12350.(28,762)	10790.(25,141)	6890.(16,054)					
LB ASH/MM BTU (kg/Mj)	10.1(4.32)	11.1	7.7(3.3)	4.8(2.07)	27.1(11.65)					
ULTIMATE, WT. PERCENT										
MOISTURE (TOTAL)	1.9	1.3	2.5	9.2	24.7					
HYDROGEN	4.6	4.7	5.2	4.7	3.5					
CARBON	65.2	70.6	68.9	63.2	41.3					
SULFUR	3.5	1.0	.7	.7	.5					
NITROGEN	1.2	1.3	1.4	1.1	.8					
OXYGEN (DIFF)	12.0	7.1	11.8	15.9	10.5					
ASH	11.6	14.0	9.5	5.2	18.7					
TOTAL	100.0	100.0	100.0	100.0	100.0					
ASH FUSIBILITY	RED ATM	RED ATM	RED ATM	RED ATM	RED ATM					
I.T. DEG F (DEG C)	2070.(1132)	2550.(1399)	2200.(1204)	2060.(1127)	2160.(1182)					
S.T. DEG F (DEG C)	2150.(1177)	2620.(1438)	2270.(1243)	2090.(1143)	2320.(1271)					
H.T. DEG F (DEG C)	2200.(1204)	2680.(1471)	2380.(1304)	2120.(1160)	2440.(1338)					
F.T. DEG F (DEG C)	2340.(1282)	2770.(1521)	2550.(1398)	2140.(1171)	2560.(1404)					
TEMP. DIFF. (F.T.-I.T.)	270.(150)	150.(83)	350.(195)	80.(44)	400.(204)					

TABLE III
ASH COMPOSITION

	MIDWESTERN BITUMINOUS	EASTERN BITUMINOUS	UTAH BITUMINOUS	WYOMING SUBBITUMINOUS	TEXAS LIGNITE
	11.6% Ash 3.5% S	14% Ash 1.0% S	9.5% Ash 0.7% S	5.2% Ash 0.7% S	18.7% Ash 0.5% S
SiO ₂	48.0	57.1	56.5	33.0	57.3
Al ₂ O ₃	16.8	25.1	19.7	15.3	19.6
Fe ₂ O ₃	15.6	6.6	3.8	7.0	4.2
CaO	6.5	1.6	7.9	13.3	9.3
MgO	1.2	0.9	1.3	2.6	1.7
Na ₂ O	1.0	1.1	3.5	7.2	0.4
K ₂ O	1.3	2.5	0.6	0.5	0.6
TiO ₂	0.9	1.8	1.3	1.2	1.5
P ₂ O ₅	---	0.4	---	---	0
SO ₃	<u>7.9</u>	<u>0.3</u>	<u>6.2</u>	<u>17.0</u>	<u>5.7</u>
	99.2	97.7	100.8	97.1	100.3
B/A	0.39	0.15	0.22	0.66+	0.21
Fe ₂ O ₃ /CaO	2.40	4.13	0.48	0.53	0.45
SiO ₂ /Al ₂ O ₃	2.86	2.28	2.87	1.96	2.93

TABLE IV
COAL ANALYSIS

	Low-S	High-S
Moisture: % by Wgt.	6.96	12.97
Volatile Matter:	33.32	35.57
Fixed Carbon:	50.84	41.36
Ash:	8.88	10.1
HHV - Btu/lb (kJ/kg)	12,532 (29,149)	11,000 (25,586)
Hydrogen:	4.64	4.32
Carbon:	70.4	59.31
Sulfur:	0.59	3.39
Nitrogen:	1.23	0.92
Oxygen:	7.15	8.96
Moisture:	6.96	12.97
Ash:	8.88	10.1
Grindability (Hargrove):	38.3	58
I.T.: °F (°C)	2700+ (1482+)	2040 (1116)
S.T.: °F (°C)	2700+ (1482+)	2085 (1141)
F.T.: °F (°C)	2700+ (1482+)	2360 (1293)
<u>Ash Composition</u>		
SiO ₂ : %	56.8	40.79
Al ₂ O ₃ :	28.6	22.98
Fe ₂ O ₃ :	6.0	21.25
CaO:	1.4	1.12
MgO:	1.15	1.12
Na ₂ O:	0.38	0.47
K ₂ O:	2.9	2.49
TiO ₂ :	1.85	0.98
P ₂ O ₅ :	0.15	0.3
SO ₃ :	0.67	3.40

IERL-RTP RESEARCH ON SULFUR CAPTURE IN LIMB

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ABSTRACT

This paper discusses EPA's in-house laboratory studies of gas/solid reactions that are expected to contribute to sulfur capture in the limestone injection multistage burner (LIMB). The research is aimed at an improved understanding of variables that determine the rate of reaction and ultimate conversion of limestone when injected into the reducing or oxidizing zone of the burner. Current work is focused on reactions which may occur in the first stage of the LIMB to form CaS. Initial results of bench-scale studies using differential and entrained-flow reactors are presented, including the reaction of H_2S with $CaCO_3$, the calcination of $CaCO_3$ to CaO , and the reaction of H_2S with CaO .

INTRODUCTION

A bench-scale study of the mechanism of sulfur capture in LIMB has been underway for the past year. This initial phase of the research is focused on reactions that can occur in the reducing zone of LIMB, capturing sulfur via CaS formation. The rationale for this emphasis on reducing-zone chemistry is based on the anticipated advantages of the CaS route over $CaSO_4$ formation which was the mechanism of sulfur capture by the earlier dry limestone injection process. These advantages are:

- 1) The equilibrium for CaS formation is favorable to higher temperatures than the $CaSO_4$ equilibrium. Because most reaction rates are very sensitive to temperature, faster rates should therefore be possible.
- 2) Unlike the $CaSO_4$ reaction, the rate of CaS formation is apparently not retarded by accumulation of the product layer. Prior studies indicate that the CaS reaction rate is limited only by chemical kinetics until conversions exceed 90 percent.

- 3) Intraparticle physical constraints, such as the pore volume available for product accumulation, should not limit the maximum extent of reaction achievable. Since CaS has a smaller molar volume than CaCO_3 , the reaction can theoretically go to completion as long as sintering does not occur. The CaSO_4 reaction, on the other hand, is limited by such constraints to about 60 percent conversion.
- 4) The reacting sulfur species should be present at higher concentrations in the first stage of LIMB, and more uniform additive/sulfur mixing can be attained in the small volume of the reducing zone.

In view of these potential advantages, it is reasonable to expect that the most efficient route for sulfur capture may involve reactions with limestone (as CaCO_3 or CaO) prior to the final stage of coal combustion - after which only CaSO_4 formation will occur. Existing literature on the reactivity of H_2S with CaCO_3 provides support for this idea, as illustrated in Figure 1. These data, from the work of Ruth, Squires, and Graff (1), show the rate of reaction as a function of temperature over the range of 550° to 750°C . Extrapolation of these data to the temperatures anticipated in a pulverized coal burner suggests that the rate would be adequate to achieve high sulfur capture in very short contact times. For example, 40 percent conversion to CaS would be predicted in 0.12 sec at a temperature of 1200°C . At 1300°C , the same conversion could be attained in 40 msec if the reaction is controlled solely by chemical kinetics.

Since the data of Reference 1 were obtained with CaCO_3 in the form of half-calcined dolomite rather than limestone, the first objective of this study is to determine if those results can be duplicated with limestone. In addition, an investigation of the kinetics of limestone calcination and the reaction of CaO with H_2S is being carried out since these reactions also bear importantly on the prospects for sulfur capture in the reducing zone of LIMB. Initial results of those studies are included here.

The extrapolation shown in Figure 1 illustrates a crucial aspect of the methodology of the IERL-RTP research: the technical feasibility of a given reaction for achieving the required sulfur capture in LIMB is judged on the basis of kinetic data obtained at moderate temperatures where reaction rates can be measured relatively accurately. If these data cannot be extrapolated on the basis of the Arrhenius relationship to yield the required conversions at combustion temperatures, the reaction is considered an infeasible basis for sulfur capture in LIMB. Such extrapolation will provide only the most optimistic prediction of the possible results.

PROCEDURE

Two types of reactors are being used, a differential reactor and an entrained-flow reactor. The differential reactor (Figure 2) is characterized by a high gas velocity (5 m/sec) and small limestone sample (15 mg). These conditions ensure that the gas-phase mass transfer resistance is minimized and that each limestone particle is exposed to the same constant concentration of H_2S ; i.e., that the change in H_2S concentration of the gas passing through the reactor is negligible. This reactor is operated at relatively low temperatures (550 to 850°C) where the reaction rates are slow

enough to yield reliable data for contact times greater than 10 sec. Limestone samples are exposed in the reactor to 5000 ppm H_2S for time periods variable from 10 sec to 30 min, after which the sample is removed and analyzed for sulfide and calcium. From these data, the conversion vs. time response can be constructed as a function of the principal reaction parameters: temperature, particle size, and gas composition.

The entrained flow reactor (Figure 3) is used to verify the extrapolation of low temperature rate measurements, made in the differential reactor, to higher temperatures appropriate to LIMB. It is a 3.2-m vertical reactor tube with full length annular preheat of the feed gas. Limestone particles are injected through a water-cooled tube at the top and are entrained in the downward gas flow for time periods ranging from 0.1 to 0.6 sec, determined by the selected gas feed rate. Wider ranges of contact time can be attained by increasing the reactor diameter or shortening its length. The exposed particles are collected in a water-cooled cyclone and analyzed to determine the degree of reaction. The reactor is operated isothermally at temperatures up to 1200°C.

RESULTS AND DISCUSSION

Limestone/ H_2S Reaction

Since limestone is essentially nonporous (as opposed to half-calcined dolomite or calcined limestone, which are highly porous), it can be expected that the reaction rate will be strongly affected by particle size. Information on the reaction rate of limestone as a function of particle size must therefore be obtained if one is to assess its prospects as a LIMB sorbent. For this purpose, several different particle size fractions of narrow size distribution were run in the differential reactor at 750°C. The particle size was varied from 90 μm to 1.6 μm . The gas fed to the reactor contained 70 percent CO_2 (balance N_2) to prevent decomposition to CaO . When the reaction rates are measured at equal conversions, they show a linear relationship with inverse particle diameter, as would be expected when the reaction is confined to the outside particle surface. Figure 4 compares the rates obtained for the smallest particles with Reference 1 data at 750°C. It indicates that the initial reactivity of half-calcined dolomite can be duplicated by limestone particles smaller than 2 μm .

The effect of temperature on the reaction rate was determined over the range 550 to 750°C. An Arrhenius plot of the rates measured at 20 percent conversion to CaS is shown in Figure 5. The temperature sensitivity is similar to that obtained from Reference 1 data with an apparent activation energy of 42 kcal/mol. Extrapolation of the limestone data to 1200°C would predict 40 percent conversion in 180 msec.

Potential problems in achieving this conversion are: 1) a strongly inhibiting effect of hydrogen on the H_2S /limestone reaction, 2) sintering of limestone particles at temperatures above 750°C, and 3) calcination to CaO before the reaction with CaCO_3 can be accomplished.

Limestone Calcination Reaction

Information on the calcination rate of limestone, especially small particles, is clearly needed to determine whether the CaCO_3 reaction can proceed. If calcination proceeds at a faster rate than the limestone- H_2S reaction, CaS formation can occur only through the CaO route - which the literature suggests is a slow reaction. (Or it will have to occur by reaction with some other reduced sulfur species such as COS or S_2 .) To obtain this information, the calcination rate of limestone particles is also being studied at IERL-RTP with the differential and entrained-flow reactors.

Another reason for undertaking calcination studies at this time is to obtain a test of the basic premise on which the reactions are being evaluated; i.e., by Arrhenius-type extrapolation of low temperature kinetic data. The calcination rate is not expected to be influenced by transient processes such as changes in internal surface area (BET--Brunauer, Emmett, and Teller) or ambiguous side reactions that can occur with H_2S . An important objective of these measurements is therefore to verify that calcination rates measured by the experimental techniques adopted for this study are consistent with the high temperature calcination rates of small limestone particles determined by previous investigators for dispersed-phase systems. These comparisons will also provide an evaluation of the entrained-flow reactor for simulating the reaction kinetics of dispersed particles in turbulent flow.

Differential Reactor Measurements. Limestone particles fractionated to a narrow size distribution averaging $1.6 \mu\text{m}$ in diameter were calcined in a manner similar to the procedure used for the H_2S reaction: 50 mg of limestone was dispersed into a quartz wool substrate, weighed, and inserted in the reactor under a pure CO_2 atmosphere. After 10 min heatup to reactor temperature, calcination was begun by displacing the CO_2 from the reactor with CO_2 -free nitrogen at a flow of 5 l./min (25°C basis) which yielded a superficial velocity of 4.9 m/sec through the limestone sample at 750°C . A series of runs was made in which the limestone particles were calcined by this procedure for varying time periods, withdrawn from the reactor, cooled under nitrogen, weighed, and analyzed for calcium content. Figure 6 shows the calcination rate obtained from these data at a reactor temperature of 750°C .

Comparison of Figures 4 and 6 shows that the calcination rate of $1.6 \mu\text{m}$ limestone particles at 750°C is considerably faster than the rate of reaction with H_2S at the same conditions. At this temperature, CaCO_3 will not react fast enough with H_2S (at the concentrations anticipated in LIMB) to form CaS before decomposition to CaO occurs. Calcination rates were measured in the same manner at other temperatures ranging from 550 to 780°C . The results, shown in Figure 7, indicate an activation energy of 46 kcal, which agrees with the values reported by others who have measured calcination rates of pure CaCO_3 by various methods⁽²⁾. The rates shown in Figure 7 are expressed in terms of the time, t^* , required to reach 50 percent conversion to CaO . It may be concluded from these data that calcination will proceed faster than the $\text{H}_2\text{S}/\text{CaCO}_3$ reaction at all temperatures. If H_2S capture is to occur as CaS , it will go through the CaO route.

Flow Reactor Measurements. The minimum exposure time in the differential reactor is about 10 sec which limits the highest temperature at which accurate calcination data can be obtained to 780°C. The flow reactor is being used for measurements at higher temperatures. Since a body of data already exists for the calcination rate of 90- μ m limestone particles in a dispersed system, the initial flow reactor tests were made at the same temperature to compare results. The earlier data were produced at Battelle-Columbus^(3,4) in a much larger (28 cm I.D. X 4.3 m) dispersed-phase reactor. The Battelle reactor operated at turbulent flow conditions and very low dispersion densities of 35-70 particles/m³ of gas throughput, using a flue gas containing 10 percent CO₂. Figure 8 compares the results of calcination data from the two reactors; it is evident that the small (1.3 cm I.D.) reactor accurately reproduces the rates obtained in the larger system.

In Figure 9, the results of the Battelle calcination rates for 90 μ m limestone particles are compared with the differential reactor data previously shown in Figure 7. Also included in this Arrhenius plot are Battelle data for 50 μ m particles and data from this study for both 50 and 90 μ m particles obtained with the flow reactor. It is evident that the difference between 90 and 50 μ m particles, as measured in the high-temperature flow reactors, is not significant and that their calcination rate is in remarkably good agreement with the rates that would be predicted by extrapolation of the 1.6 μ m data obtained with the differential reactor. The results shown in Figure 9 suggest that the calcination rate of particles smaller than ~ 100 μ m is independent of particle size.

A test of this conclusion is shown in Figure 10. Using the differential reactor, calcination rates were measured at 780°C with 10 and 90 μ m particles and compared with the 1.6 μ m data. The results tend to confirm that limestone particle size does not affect its calcination rate. Additional measurements showed similar results over the full range of temperatures, 550 to 780°C. All of the differential reactor data of Figures 6, 7, 9, and 10 were obtained at the same particle loading (80 mg of limestone per cm² of reactor cross section) and the same gas velocity of 490 cm/sec (at 750°C). That these conditions are truly differential, for the full range of particle sizes tested, has not yet been verified.

For the data so far collected, a simple kinetic model correlates the limestone calcination rate over five orders of magnitude and correlates particle size over two orders. An additional tentative conclusion is that the low-temperature differential reactor data can be extrapolated to yield reliable estimates of high temperature rates in dispersed systems.

Reaction of H₂S with CaO

Pell⁽⁵⁾ studied the reaction of H₂S with CaO in the form of fully calcined dolomite and found a slower rate than the reaction of H₂S with half-calcined dolomite (CaCO₃). Comparison of the slopes of the Arrhenius plots in Figure 11 shows that the activation energy is also lower for the CaO reaction, and extrapolation of those data predicts that very long contact times would be required for significant sulfur capture, even at the highest temperatures expected in LIMB. Also shown in Figure 11 are data reported by Keairns⁽⁶⁾ et al. for CaO prepared from four different limestones, which agree well with Pell's results. At a reaction temperature of 870°C, the time

required for 40 percent conversion to CaS is about 10 minutes. On the basis of those results, no sulfur capture would be expected in LIMB via the $\text{H}_2\text{S}/\text{CaO}$ mechanism.

Before discussing the results of the IERL-RTP experiments with $\text{H}_2\text{S}/\text{CaO}$, it will be helpful to review some pertinent background regarding earlier work on the CaO/SO_2 reaction. Many studies of the CaO/SO_2 reaction were conducted as part of the EPA program to develop the dry limestone injection process in the 1960s. Laboratory measurements, made with various types of reactors, invariably showed the reaction rate to be much too slow to account for any significant SO_2 capture during the short residence time available in a boiler. This was so even though the laboratory measurements were made at the same temperature and gas composition as the boiler environment. At best, the rates obtained in the laboratory were only 5 percent of the rate necessary to obtain the conversions actually observed when limestone was injected in boiler tests.

In making those comparisons, the reaction rates were expressed in terms of mols of SO_2 reacted per mol of CaO (or CaCO_3 injected) per second. By 1970, the role of the internal pore structure of calcined limestone on the SO_2 reaction was better understood, and it was established that the reaction occurred throughout the pore structures of small particles (less than $100\mu\text{m}$) at a rate directly proportional to the internal (BET) surface area of the solid. The BET surface areas of the CaO used in the early studies typically had values of 2 to 3 m^2/g and were prepared by calcining 10/28 mesh limestone in a rotary kiln at 980°C for 2 hr. Such conditions are considered a "soft burn" in the lime industry and are necessary to achieve complete (>90 percent) conversion to CaO in large batches. In contrast, BET analyses of calcines prepared in dispersed systems such as the Battelle reactor in time periods less than 1 sec showed specific surface areas as large as 67 m^2/g CaO . Other tests made by Ishihara⁽⁷⁾ in Japan showed an average BET surface area of 23 m^2/g for CaO prepared by injecting limestone particles into a 1200°C reactor for short residence times. The existence of large specific surface areas immediately following CaCO_3 decomposition is a phenomenon predicted on theoretical grounds, and the values observed when calcination is very fast and rapidly quenched can be explained by transient processes occurring in the crystal lattice during that period.

The BET surface areas of limestone particles calcined in the IERL-RTP flow reactor are in the range 30 to 50 m^2/g , determined by nitrogen adsorption at 78°K .

The point of this discussion is that the earlier discrepancy between reaction rates observed in the laboratory and those measured in furnaces can be completely resolved on the basis of the measured difference in surface area. Notwithstanding other possible interpretations of the facts, one is led to the conclusion that high CaO reactivity (and rapid SO_2 capture) occurs in dispersed systems only during the transient period of high surface area during, and immediately following, CaCO_3 decomposition. This interpretation also explains such characteristics as the rapid flagging of SO_2 capture, loss of reactivity at high injection temperatures, and the poor performance of pre-calcined lime in injection tests.

Returning to the subject of the $\text{CaO}/\text{H}_2\text{S}$ reaction, Figure 12 shows the results of measurements of the reaction rate of CaO obtained in this study. The reaction rates were measured in the differential reactor at a temperature of 700°C . When the limestone particles are calcined for 7.5 min (the minimum time required to reach 90 percent calcination in flowing N_2 at 700°C), the CaO subsequently reacts with 5000 ppm H_2S at a rate fast enough to achieve 70 percent conversion to CaS in 5 sec. This rate is more than an order of magnitude greater than that obtained by Keairns et al.⁽⁶⁾ or Pell⁽⁵⁾ and, as indicated by the comparisons of Figure 13, is also much faster than the reaction with half-calcined dolomite. Although neither Keairns nor Pell reported BET surface-area data, it can be assumed from the manner of preparation that the calcines had low surface areas similar to those which characterized the earlier CaO/SO_2 laboratory studies. The BET surface area of the 700°C calcine shown in Figure 12 is $45 \text{ m}^2/\text{g}$. The high surface areas characteristic of "flash" calcination in dispersed-phase reactors is thus reproducible in the differential reactor when small particles are calcined for time periods sufficient only to complete the CaCO_3 decomposition.

The above discussion suggests that the $\text{H}_2\text{S}/\text{CaO}$ reaction rate, like that of SO_2/CaO , increases with BET surface area. That this is so is demonstrated by the additional experiments shown in Figure 12, where calcination conditions were extended to longer time periods and higher temperatures to induce sintering. The calcination conditions were chosen to vary the BET surface areas over a broad range. The results show that the reaction rates (all of which were determined at 700°C) drop sharply as the surface area of the CaO is reduced. It is apparent, therefore, that the same transient phenomena that are responsible for SO_2 capture in dispersed systems will be equally important for H_2S capture in the reducing zone of LIMB. These phenomena include both the high BET surface areas generated by rapid calcination and the dissipation of that surface by high temperature sintering.

All of the CaO data reported here were obtained with 45 percent hydrogen in the reactor gas. Unlike the CaCO_3 reaction, the reaction of H_2S with CaO is not inhibited by hydrogen.

The effect of temperature on the $\text{CaO}/\text{H}_2\text{S}$ reaction is shown in Figure 14. These data were obtained with CaO calcined for 2 hours at 950°C which ensured that the surface area remained constant; i.e., was not affected by the different reaction temperatures. The activation energy is considerably lower than the CaCO_3 reaction (19 vs 42 kcal/mol), but this disadvantage is compensated for by the higher reaction rate. Extrapolation of the data of Figure 14 to 1200°C predicts that 40 percent conversion to CaS could be achieved in 90 msec.

SUMMARY

The general picture emerging from the work completed so far at IERL-RTP indicates that:

- The kinetics, as well as the thermodynamics, of sulfur capture by limestone in the reducing zone of LIMB is favorable. The reaction rates observed in this study are sufficiently fast to expect efficient sulfur capture in the reducing zone if no factors other than chemical kinetics limit the reaction.

- Sulfur released as H_2S in the reducing zone of LIMB can be captured through the CaO mechanism, but not by direct reaction with limestone. Consequently, the variables which affect calcination, porosity, and surface area can be expected to play a crucial role.
- The laboratory techniques utilizing kinetic data from differential reactors appear to yield reliable estimates of the results obtainable in dispersed systems. The phenomena that are probably responsible for sulfur capture in LIMB (whether in the reducing or oxidizing zone) can be reproduced and studied under controlled laboratory conditions.

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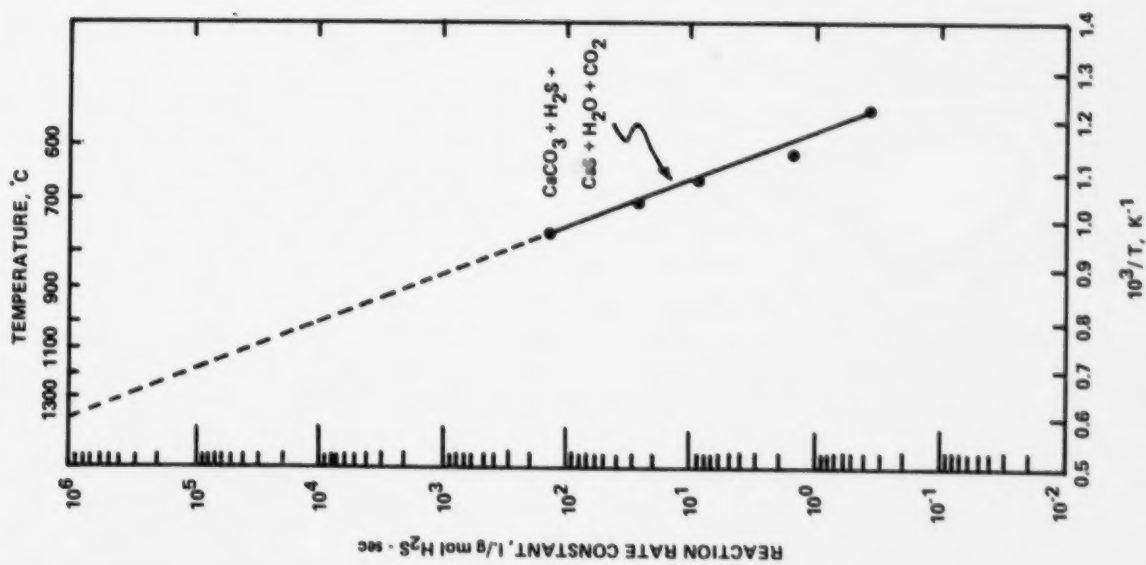


Figure 1. H₂S Capture by Half-Calcined Dolomite. Data of Ruth, Squires, and Graff (1972).

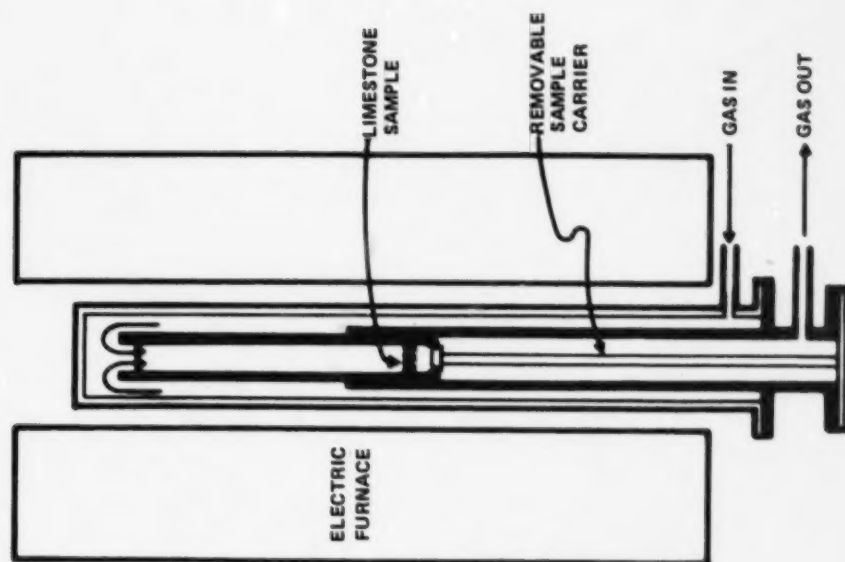


Figure 2. Differential Reactor.

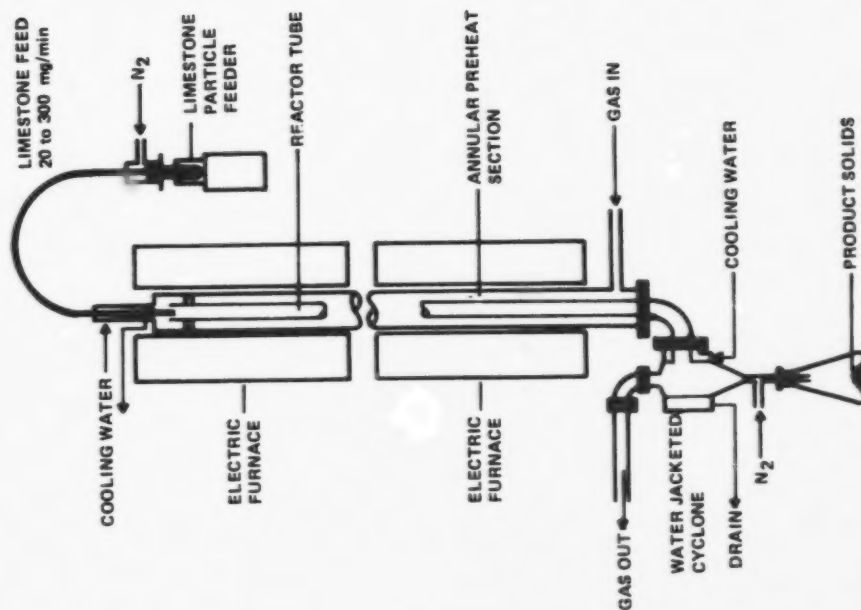


Figure 3. Entrained-Flow Reactor.

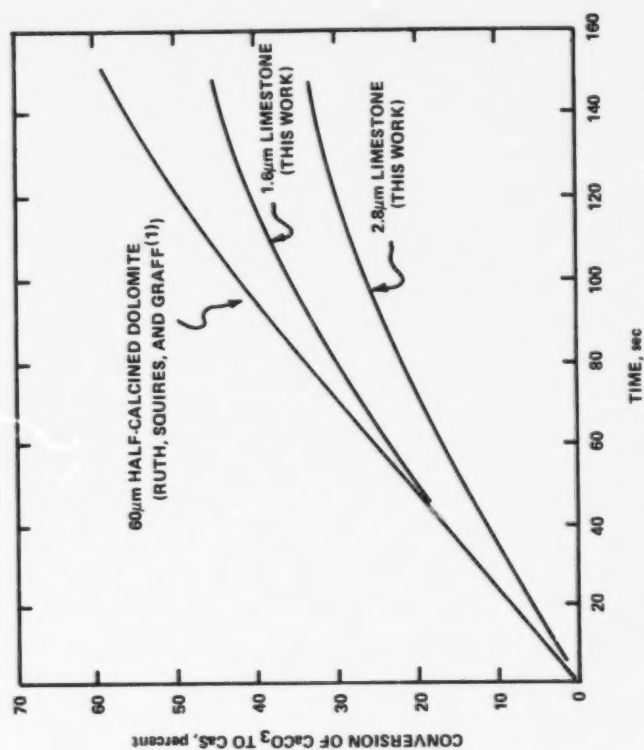


Figure 4. Comparison of the Reactivities of Limestone Particles and Half-Calcined Dolomite with 5000 ppm H_2S at $750^\circ C$.

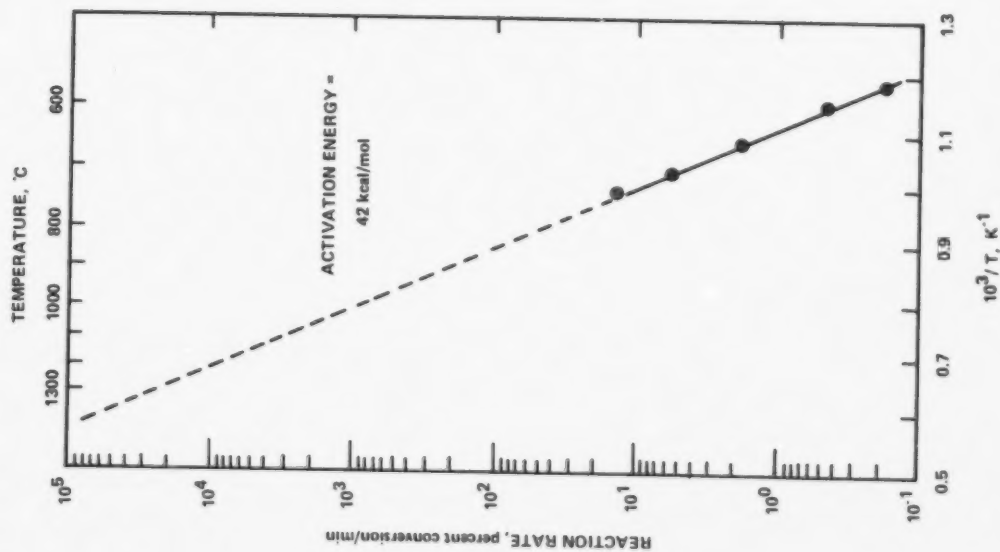


Figure 5. Effect of Temperature on the Reaction Rate of 2.8 μm Limestone Particles with 5000 ppm H_2S . Rates Evaluated at 20 Percent Conversion to CaS .

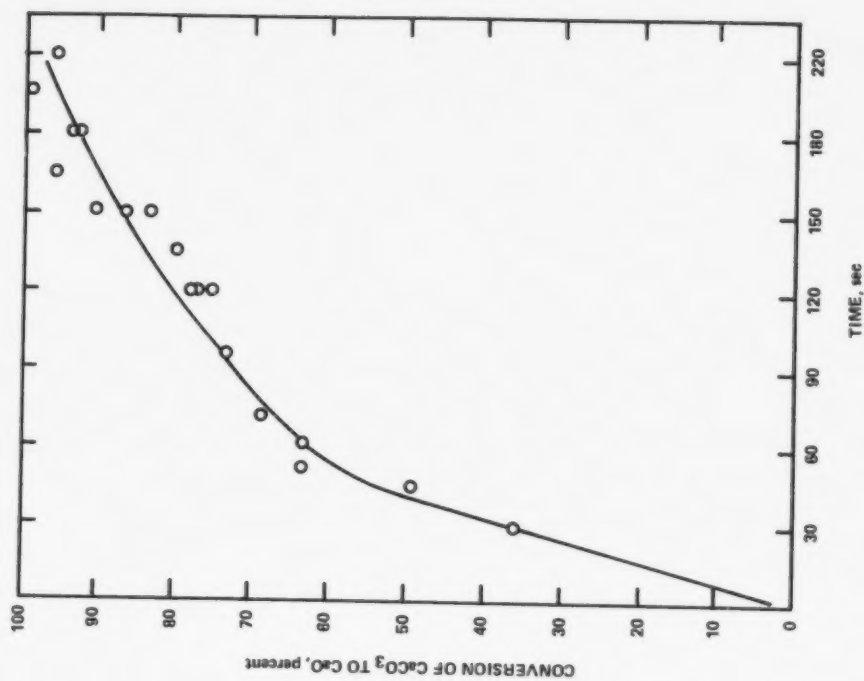


Figure 6. Calcination of 1.6 μm Limestone Particles at 750 $^{\circ}\text{C}$. Gas Velocity (Nitrogen) = 4.9 m/sec.

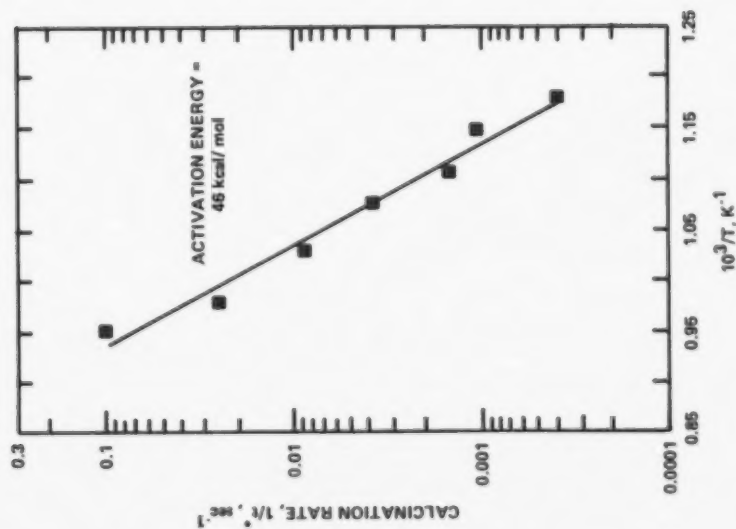


Figure 7. Effect of Temperature on the Calcination Rate of $1.6\mu m$ Limestone Particles in the Differential Reactor.

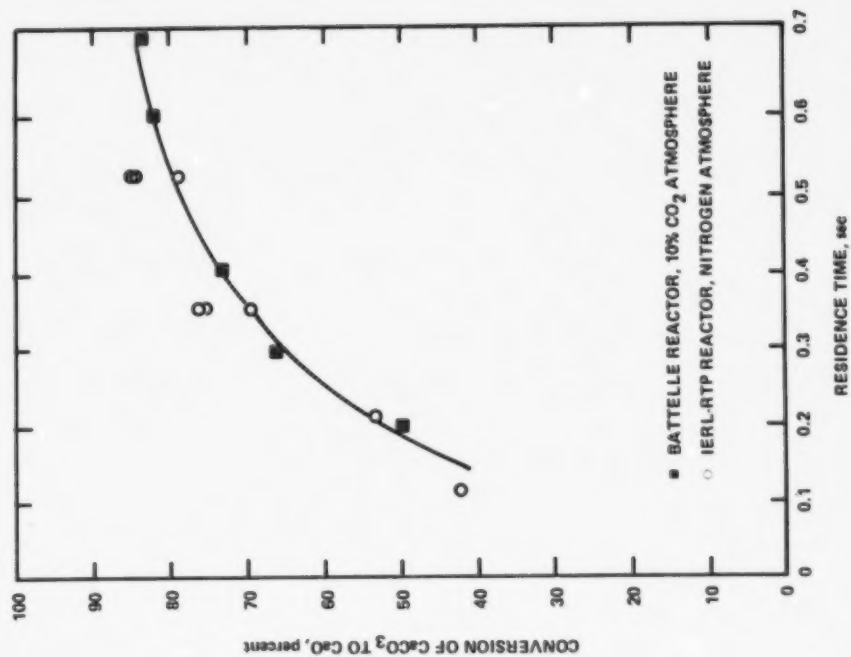


Figure 8. Comparison of Calcination Rates in Dispersed-Phase Reactors. $90\mu m$ Limestone Particles, $1090^\circ C$.

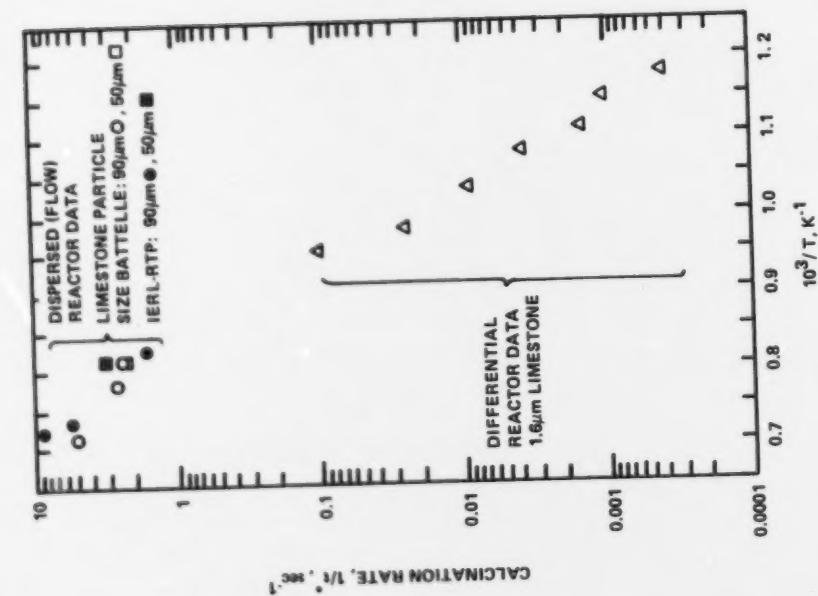


Figure 9. Comparison of Differential and Entrained-Flow-Reactor Calcination Rates.

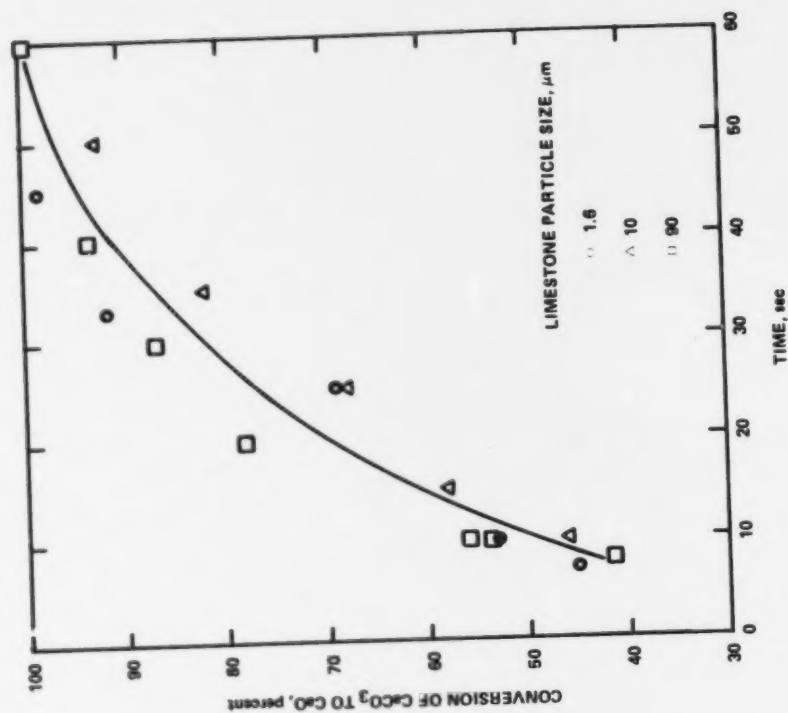


Figure 10. Effect of Limestone Particle Size on Calcination Rate in Differential Reactor; 780 $^{\circ}\text{C}$.

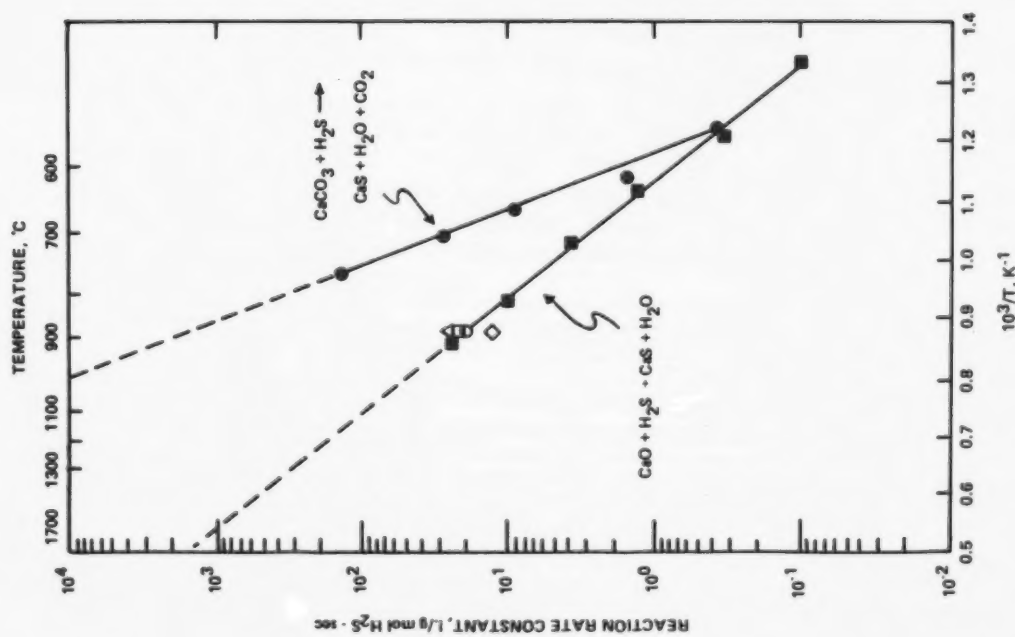


Figure 11. Comparison of CaO and CaCO₃ Reaction Rates. Data of Ruth⁽¹⁾ for Half-Calcined Dolomite ●; Data of Pell⁽⁵⁾ for Fully Calcined Dolomite ■; Data of Keairns et al. (6) for Calcined Limestones △ □ ○ ◇.

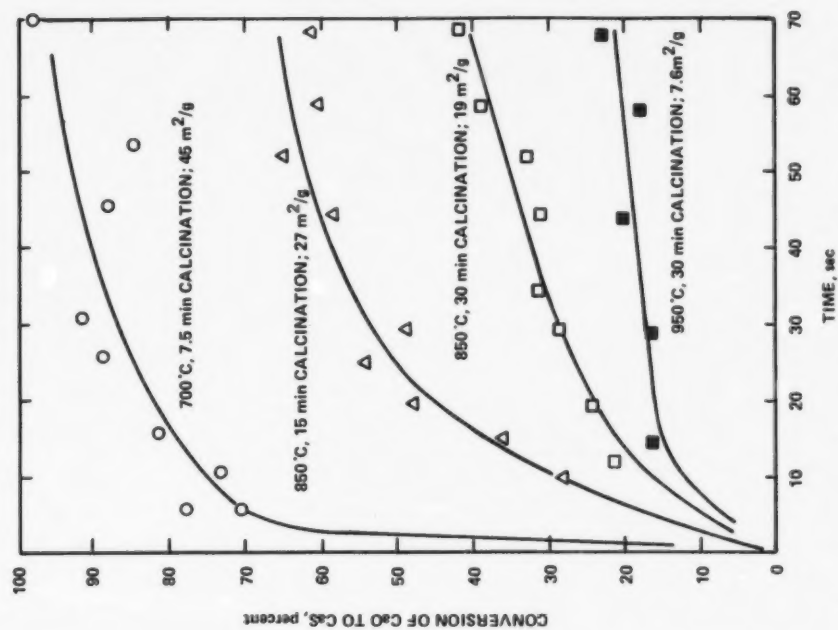


Figure 12. Effect of Calcination Conditions (in Differential Reactor) on the Reactivity of CaO with 5000 ppm H₂S at 700°C.

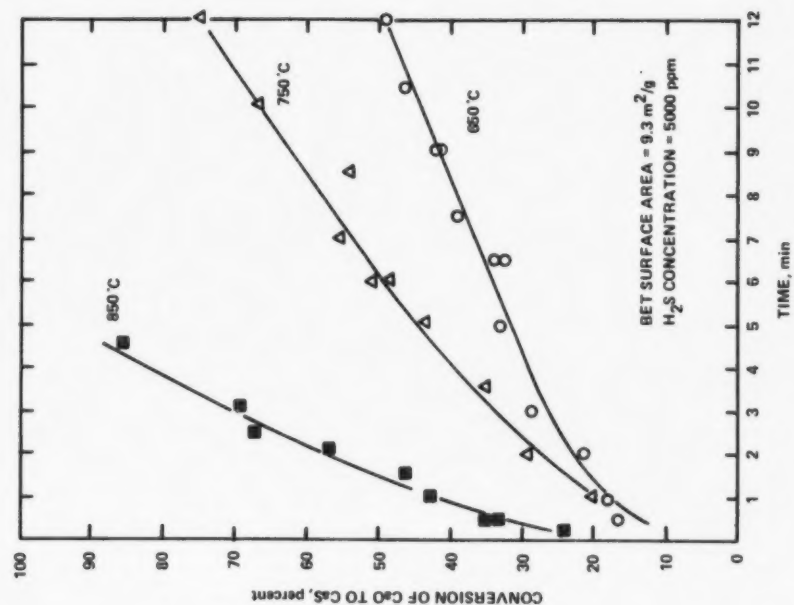


Figure 14. Effect of Reaction Temperature on H₂S Capture by CaO in Differential Reactor. Limestone Calcined at 950°C for 30 min.

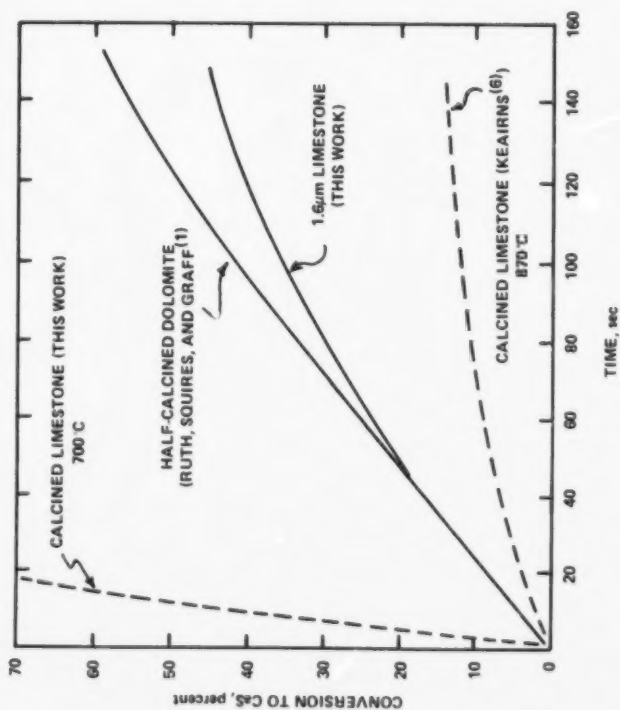


Figure 13. Comparison of IERL-RTP Reaction Rate Data with Data of Other Investigators. H₂S Concentration = 5000 ppm.

LIMB TESTING:
THE USE OF DRY SORBENTS TO REDUCE SULFUR OXIDE EMISSIONS
FROM PULVERIZED-COAL FLAMES UNDER LOW-NO_x CONDITIONS

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ABSTRACT

This paper addresses the problem of limestone sorbent injection into multistaged burner (LIMB) pulverized-coal flames to reduce sulfur dioxide emissions. It also describes experimental studies conducted at both pilot and bench scale. Pilot scale tests were conducted in two research furnaces firing at up to 20.5 MW (70×10^6 Btu/hr), with a prototype distributed mixing burner. With limestone injection, sulfur dioxide captures of 30 to 40 percent were obtained for Ca/S molar ratios of 2. Test data show that burner design, coal type, and mode of sorbent injection all influence the sulfur capture process. Thermal environment in the combustor has a significant impact on sorbent utilization, depending upon the location of sorbent injection.

Under conditions of low NO_x operation two modes of sulfur capture are possible: capture under fuel-rich and fuel-lean conditions. A series of bench scale (1×10^6 Btu/hr firing rate) studies were carried out to determine the parameters controlling capture in these two modes. Under fuel-lean conditions, the thermal history of the sorbent dictates sulfur capture. Under fuel-rich conditions, the process is more complex. The bench scale studies indicate that sulfur is retained in the coal in the fuel-rich region and that regeneration of gaseous sulfur during second-stage burnout is possible. Rich-zone stoichiometry had an impact on sorbent utilization in the bench scale studies; utilization was low under highly staged conditions ($SR_1 < 0.7$). The effect of sorbent and fuel type was investigated. Five sorbents were used: two calcites, one marl, one dolomite, and one hydrated lime. Under all of the conditions investigated, the dolomite had the highest utilization (a maximum of 30 percent). Three fuels were used: a bituminous coal, a lignite coal, and propane doped with SO₂. It was found that fuel type has an impact on sulfur capture and that this effect was not entirely attributable to thermal effects.

INTRODUCTION

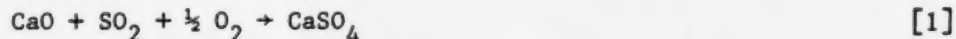
Legislation requiring the removal of atmospheric pollutants from the combustion products of coal-fired steam generators increases power generation costs. Consequently there are considerable incentives to develop cost effective pollution control techniques for conventional coal-fired combustors. Provided combustion is completed efficiently, impurities in the coal are the major source of pollutants. Inorganic material produces fly ash, and sulfur and nitrogen are oxidized during combustion forming sulfur and nitrogen oxides. Pollutant control techniques can involve: removal of the impurities prior to combustion, flue gas cleaning, or modification of the combustion process to prevent the formation of pollutant species. The latter approach, which is the subject of this paper, is likely to have a minimal impact on power generation costs.

Coal sulfur does not necessarily convert quantitatively to sulfur oxides in the combustion products. Coals with high alkali metal oxide contents retain significant quantities of sulfur in the ash as sulfates. Thus, one method of preventing the emission of sulfur oxides is to effectively increase the alkali metal concentration in the system. This may be accomplished by adding alkali to the coal (1) or by injecting a sorbent which will capture sulfur into the combustion chamber. The injected sorbent (generally calcium carbonate) flash-calcines and reacts with gaseous sulfur species forming solid calcium sulfite and/or calcium sulfate. The solid sulfur compounds are then collected with the fly ash at the boiler exit. Considerable effort was expended in the late 1960's and early 1970's on development and demonstration projects (2) based on this process. Although pilot plant studies showed promise, the results could not be duplicated in full-scale systems. The lack of success was attributed to deadburning and maldistribution of the sorbent. Recent pilot scale studies (3, 4) with low- NO_x coal burners suggest that sorbent injection could be more effective under conditions which minimize NO_x formation.

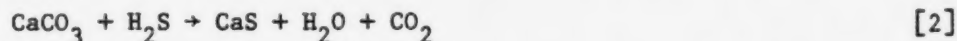
The minimization of NO_x formation in pulverized-coal flames requires the generation of extensive fuel-rich zones and the reduction of peak flame temperatures. Thus, limestone sorbent injection into multistage low- NO_x burners (LIMB) may provide the opportunity to control emissions of both sulfur and NO_x by modifying the combustion process to prevent their formation. Sulfur capture by sorbent injection involves three processes, namely:

- Sorbent activation - the sorbent particles are heated and calcined. Particle reactivity depends upon initial properties and peak particle temperature.
- Capture - sulfur species (H_2S , COS , or SO_2) react with the sorbent producing either sulfate or sulfide.
- Regeneration - the spent sorbent may decompose, regenerating gas-phase sulfur species.

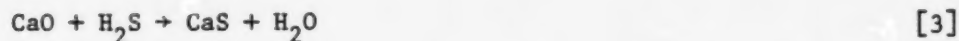
The general reaction describing sulfur capture under oxidizing conditions:



has been studied extensively in thin-bed and dispersed-flow reactors by several workers (5, 6). However, none of these studies duplicated the time-temperature conditions that prevail in pulverized-coal flames. Borgwardt (7) has suggested that reactions such as:



and



could become significant under fuel-rich conditions. Extrapolation of rate data for such reactions (7) indicates that reaction [2] is fast enough to allow significant sulfur capture in coal flames.

Consequently, there are two possible modes by which calcium-based sorbents can capture sulfur species in a pulverized-coal-fired combustor operating under low- NO_x conditions. In fuel-lean regions reaction [1] may proceed because the lower temperature will reduce deadburning. In the fuel-rich region, reaction [2] may be significant, and then retention of sulfur in the solid phase under fuel-lean conditions becomes an important factor in the overall process. Equilibrium calculations indicate that conversion of calcium to the sulfate or sulfide is very high (> 80 percent) under either fuel-rich or fuel-lean conditions but that the sulfate decomposes at much lower temperatures than the sulfide. At stoichiometric conditions the sulfate is relatively unstable suggesting that prolonged residence times at stoichiometric conditions could reduce overall sulfur capture even though high captures occur in the fuel-rich zone.

This paper describes bench and pilot scale studies designed to establish the factors controlling sorbent utilization and the potential of sorbent injection to reduce sulfur oxide emissions from pulverized coal combustion. Data are presented for a nominal 20.5 MW (70×10^6 Btu/hr) prototype low- NO_x coal burner firing in two different experimental furnaces. Bench scale studies, under more closely controlled conditions, were carried out in a nominal 0.3 MW (1×10^6 Btu/hr) facility designed to simulate the temperature-time history of a complete steam generator.

EXPERIMENTAL SYSTEMS

Pilot Scale Burner

A prototype low- NO_x distributed mixing burner (DMB) developed under U.S. EPA support was used in the pilot scale studies. The burner was designed by integrating the DMB design criteria and Foster Wheeler Energy Corporation design parameters, and is shown schematically in Figure 1.

A substoichiometric amount of air is supplied to the burner throat, creating a fuel-rich region close to the burner. The remainder of the combustion air is added through four outboard staged air ports located at the periphery of the exit divergent. Under nominal conditions 70 percent of stoichiometric air is supplied to the burner throat, and the burner operates with an overall 20 percent excess of air. The impact of design variables on NO emissions has been discussed elsewhere (8); in this study burner parameters were fixed. The sorbent was added either with the coal or with the staging air through the outboard staged air ports.

Test Furnaces

The prototype burner was tested in two spray-cooled furnaces. The inner walls of both furnaces are partially covered with refractory. The configuration of the larger furnace (LWS, maximum firing rate 150×10^6 Btu/hr) is typical of conventional boiler practice and provides a thermal environment in the burner zone similar to that encountered in industrial and utility boilers. At the firing level the furnace is 22 feet deep and 16 feet wide. The smaller test furnace (MT, maximum firing rate 60×10^6 Btu/hr) is cylindrical with a diameter of 14 feet and a length of 20 feet. Figure 2 compares the geometries of these test furnaces.

During the DMB tests in the LWS furnace the burner was operated at its design capacity of 20.5 MW (70×10^6 Btu/hr). Due to confinement restrictions, the burner could not be fired at this rate in the MT furnace. The nominal firing rate of the DMB was therefore reduced to 15.8 MW (54×10^6 Btu/hr) in the MT, which produced a flame of acceptable proportions.

Bench Scale System

The bench scale facility used in these studies has a nominal capacity of 0.3 MW (1×10^6 Btu/hr) and is capable of duplicating the history of the solid particles (coal and sorbent) and the products of combustion in a pulverized coal-fired steam generator. The facility (Figure 3) consists of three major components:

- A radiant furnace, a vertical refractory-lined cylinder which simulates the firing zone. Removable cooling tubes provide heat extraction. Some early studies were also carried out with a horizontal furnace configuration.
- A postflame cavity which simulates the space between the firing zone and the superheater.
- A convective section, cooled by banks of air cooled stainless steel tubes.

The facility was operated in two ways to investigate different modes of sulfur capture. When the sorbent was injected with the staging air through the staged air ports of a small-scale low- NO_x burner, sulfur capture would occur primarily under fuel-lean conditions. Alternatively when the staging air was added downstream, at the entrance to the postflame cavity, (Figure 3)

the whole of the radiant furnace operated fuel-rich and sulfur capture under fuel-rich conditions could be investigated.

Measurement Systems

The measurement of sulfur species in combustion products containing active sorbents introduces several sample acquisition problems. Sulfur species are water soluble and highly reactive with calcium-based sorbents at temperatures higher than, but close to, the dew point. A "phase discrimination" probe has been designed, constructed, and tested which minimizes gas/solid contact after sample extraction (8). Figure 4 illustrates the design features of the probe and shows the associated sample conditioning system. The gas-phase sample is extracted from the main particle-laden sample stream at right angles to the flow and at a relatively low velocity. The hot gas sample passes through a short, heated sample line directly into a DuPont 400 nondispersive, ultraviolet-absorption, continuous SO₂ analyzer. This SO₂ measurement system has been directly compared with wet chemical and other analytical techniques and has shown good consistent performance. In the bench scale studies concentrations of H₂S and COS were measured by gas chromatography using a flame photometric detector and a Porapac QS column.

In all cases the reported sulfur capture is based upon measured SO₂ emissions without additive and not on sulfur dioxide concentrations calculated from input coal sulfur content. This allows measurement of only sorbent capture and does not include inherent capture by alkali compounds present in the coal. It also eliminates inaccuracies due to variations in the input sulfur level (due to the heterogeneous nature of coal).

Fuels and Sorbents

During the course of this study experiments have been carried out with four coals, one coal/water slurry, and five different sorbents. The characteristics of these different fuels and sorbents are presented in Tables 1 and 2. The pilot scale tests discussed in this paper were carried out with Utah and Indiana coals and preground Vicron 45-3 limestone.

PILOT SCALE TESTS

The prototype DMB was tested in two furnaces, the LWS and the MT. This burner has been tested extensively in order to optimize its performance under low-NO_x conditions, and four burners of this design have been installed in a small utility boiler (8, 9). In these tests the sorbent was injected either with the coal or through the outboard staged air ports. The sorbent was not mixed with the staged air; rather, the sorbent injection nozzle was located close to the exit on the axis of the air nozzle. Sulfur capture was routinely based upon flue gas sulfur dioxide concentrations measured with and without sorbent addition; tests were carried out to assess the accuracy of the capture values determined in this manner. Figure 5 presents data comparing sulfur capture calculated from flue gas sulfur dioxide concentrations and fly ash sulfur content for two coals. It can be seen that there is very good agreement between the two methods of determination. It should be

noted that in these studies no attempt was made to optimize the burner for SO_2 reduction. This will be the subject of future tests.

Coal Sulfur Content

Figure 5 shows that sulfur capture is dependent upon coal properties: at a given Ca/S molar ratio sulfur capture increases with increasing coal sulfur content. Previous investigators (5) have suggested that sulfur capture is proportional to the square root of the sulfur dioxide concentration. Figure 6 presents an example of the use of the parameter $\sqrt{S} \cdot \text{Ca/S}$ as a means of comparing sulfur capture from coals of different content (S is the sulfur content of the coal calculated on a dry ash-free basis). The data presented in Figure 6 provides an example of the potential usefulness of this parameter. For coals which exhibit high levels of inherent capture it is probable that $(\text{SO}_2)^{1/2}$ (where SO_2 is the flue gas sulfur dioxide concentration measured without additive) would improve the correlation for different coal types.

Sorbent Injection Location

In the pilot scale studies three different sorbent injection locations were used: 1) the sorbent was added to the coal prior to the mill, 2) the sorbent was injected through all four staged air ports, and 3) the sorbent was injected through two ports (either the upper or lower pair). Because the same amount of transport air was used for two- or four-port injection, when the sorbent was added through two ports the injection velocity increased. Figure 7 compares sulfur captures measured in the LWS for two coals (Utah and Indiana 1). With sorbent addition in the three locations described above, it can be seen that for both coals capture is highest with the high velocity tertiary port injection. Injection with the coal or through four ports gives very similar captures, except that in some cases injection with the coal is superior at high Ca/S molar ratios. Although these conclusions about the impact of sorbent injection location are dependent upon the test combustor configuration, they indicate that the initial thermal history of the sorbent has a strong impact on sulfur capture.

Test Combustor

The pilot scale investigations carried out with the EPA prototype low- NO_x burner in the LWS and MT combustors indicate that there is a consistent effect on sulfur capture associated with the combustor configuration which in turn depends upon sorbent injection location. Figure 8 presents data comparing sulfur capture for different coals in the two test furnaces when Vicron was added either through the staged ports or to the coal before the mill (the correlation discussed earlier is used to account for coal sulfur effects). It can be seen that for sorbent injection with the coal there is essentially no difference between the two furnace systems. When the sorbent is injected with the staged air, capture is highest in the LWS.

Sulfur capture by the injection of dry sorbents is strongly dependent upon the thermal history of the sorbent particles. It is quite probable that the initial heating rates and peak temperatures experienced by the particle

can be particularly significant. It is unlikely that the combustors used in these investigations have a first order impact on flame temperatures or the internal flame structure. Consequently, it is not surprising that sulfur capture with sorbent injection in the mill is relatively insensitive to combustor configuration because the local temperatures within the flame in the near burner region will be similar in both cases. This is not the case when the sorbent is injected with the staged air. The external recirculation zone temperature in the LWS is much lower than that in the MT. Thus, the initial temperature and heating rate experienced by the sorbent particles is very different for these combustors when the sorbent is injected with the staged air, and therefore sulfur capture is affected by combustor type when the sorbent is injected with the staging air.

Summary - Pilot Scale Studies

The pilot scale studies (with the EPA prototype low- NO_x burner) suggest that the injection of sorbents at a Ca/S molar ratio of 2 can produce a 50 percent reduction in SO_2 emissions. Capture is extremely dependent upon thermal environment and injection conditions, especially for fuels with sulfur contents greater than 1.5 percent. The pilot scale results suggest that the application of LIMB (limestone injected multistage burner) technology will be system dependent. Optimum conditions will vary dependent upon boiler design, coal type, sorbent type, and firing conditions.

BENCH SCALE STUDIES

The bench scale studies were designed to screen a large number of parameters in order to identify those which control the capture of SO_2 by dry sorbents under low- NO_x conditions. The bench scale studies were divided into three test series, the first of which was concerned with screening combustion parameters, and the second of which investigated in greater detail the impact of thermal environment and sulfur chemistry. Both sets of tests were carried out with the Vicron 45-3 limestone and the Indiana coal. The earliest results have been reported elsewhere (9). It was found that heat extraction had a large impact upon sulfur capture. Sulfur capture increased considerably as heat was removed from the flame zone. Excess air and sorbent injection location had minor effects; sulfur capture increased significantly when the sorbent was added with the staged air at high velocity. Detailed measurements under fuel-rich conditions indicated that the gas-phase sulfur concentration was limited by sulfur evolution from the solid, and that significant quantities of SO_2 and COS were present. The third series of bench scale tests were primarily concerned with the impact of fuel and sorbent properties. The data from this series is discussed in the following sections.

Sorbent Type

All of the data reported earlier for the pilot scale studies were carried out with a Vicron 45-3 limestone (see Table 2). Tests were carried out in the bench scale system to investigate the impact of sorbent type on sulfur capture. Figure 9 compares sulfur captures obtained when various sorbents were injected with the fuel (Indiana 2 coal) without additional

cooling in the bench scale facility. It can be seen that the best captures, approaching 50 percent at Ca/S molar ratios of 2, were obtained with dolomite. In contrast to results reported by other investigators (4) captures with calcium hydroxide were less than those obtained with limestone or dolomite. Very little difference in capture was observed with the different particle sizes of Vicron. The results with the two Vicrons may not be indicative of the impact of particle size, as both of these sorbents had relatively small mean diameters. The results obtained when the Michigan marl was screened to below 200 mesh showed an almost threefold increase in capture. The unscreened marl had a larger particle size and a significant fraction of silica and alumina impurities.

Fuel Type

Tests to investigate the effect of fuel type on sulfur capture were performed. Figure 10 compares capture obtained with three different fuels when Vicron 45-3 was injected with the fuel. Propane doped with H_2S gave captures similar to those obtained with a Beulah lignite; these were considerably greater than the captures obtained with the Indiana 2 coal. The different sulfur captures may be attributed to different thermal environments resulting from different flame characteristics of the fuels or to differences in other fuel properties such as ash composition. Certainly the adiabatic flame temperature of both propane and the lignite coal is less than that of the Indiana coal. Figure 11 compares wall and gas temperatures measured for propane and Indiana coal. It can be seen that there is very little difference in the furnace temperature for the two fuels, although at very short residence times there is a difference between the measured gas temperatures. It should be remembered that this is merely a single point measurement and may not be indicative of the peak temperatures in the system. Figure 11 also shows the sulfur capture at three residence times (three sample locations) for both fuels. The bulk of the capture occurs in the postflame region between sampling locations 1 and 2. It is interesting to note that sulfur captures in excess of 70 percent at Ca/S molar ratios of 2 were obtained with propane doped with H_2S without burner staging, under uncooled furnace conditions. Exhaust NO_x levels were greater than 1100 ppm at these conditions. Since the total emission is due to thermal NO formation and since the production of such quantities of thermal NO requires high temperatures, sorbent injected with the fuel must have experienced some very high temperatures. These temperatures did not deactivate the sorbent which implies that the difference observed in Figure 11 between sulfur capture with coal and doped propane may not be due to thermal effects, but could be due to some chemical deactivation of the sorbent. The deactivation may be due to the presence of coal or to inorganic minerals which are vaporized and deposited on the sorbent.

Combustion Conditions

The bench scale facility was designed to allow investigation of the influence of combustion conditions on sulfur capture. The sorbent could be added either with the fuel or the staged air of a subscale distributed mixing burner, or the radiant furnace could be operated entirely fuel-rich and the sorbent injected downstream with the staging air. These two conditions are

referred to as burner staging and physical staging. Figure 12 presents data which compares sulfur capture for three sorbents under both of these conditions. It can be seen that in every case the capture obtained when the system was physically staged was superior to that obtained under burner staging. This suggests that the thermal history produced under physically staged conditions was more conducive to sulfur capture than that produced with burner staging. These results imply that the combination of sorbent and second-stage fuel injection (reburning) could provide an effective method of reducing both NO_x and SO_x from coal-fired boilers.

CONCLUSION

The data presented in this paper suggest that the LIMB process (limestone injection multistage burners) could give sorbent utilization in excess of 25 percent at a Ca/S molar ratio of 2 with a medium-to-high-sulfur coal. However, sorbent utilization is dependent on fuel type, sorbent type, and the thermal history of the sorbent. Since the process is strongly dependent upon thermal history, system effects dominate. Figure 13 presents a qualitative description of the LIMB process. There are two keys to the process. Firstly, the sorbent must be activated, and secondly it must be mixed with the gaseous sulfur species for a sufficient time in the optimum temperature regime for sulfation to occur. Figure 13 shows sorbent reactivity as a function of time for three temperatures. Temperature T1 is too low to activate the sorbent. Temperature T3 is too high because, although the sorbent is activated at very short times, it quickly loses its reactivity at the high temperature. The optimum temperature, T2, provides a maximum reactivity at intermediate residence times. The sulfation requirement is also illustrated in Figure 13; unless the sorbent remains for a sufficient length of time within the temperature regime required for sulfation, sorbent utilization will be poor. Consequently, both the heat release zone and the sorbent injection system must be optimized to provide an active sorbent and sufficient residence time in the optimum temperature regime. Further efforts are underway to quantify the qualitative picture presented in Figure 13. It should be remembered that the ultimate success of the LIMB process will be dependent upon the impact of sorbent injection on plant performance. Increasing the amount of inorganic material within the radiant section of the boiler can adversely affect heat transfer, slagging in the radiant furnace, and fouling of the convective passes.

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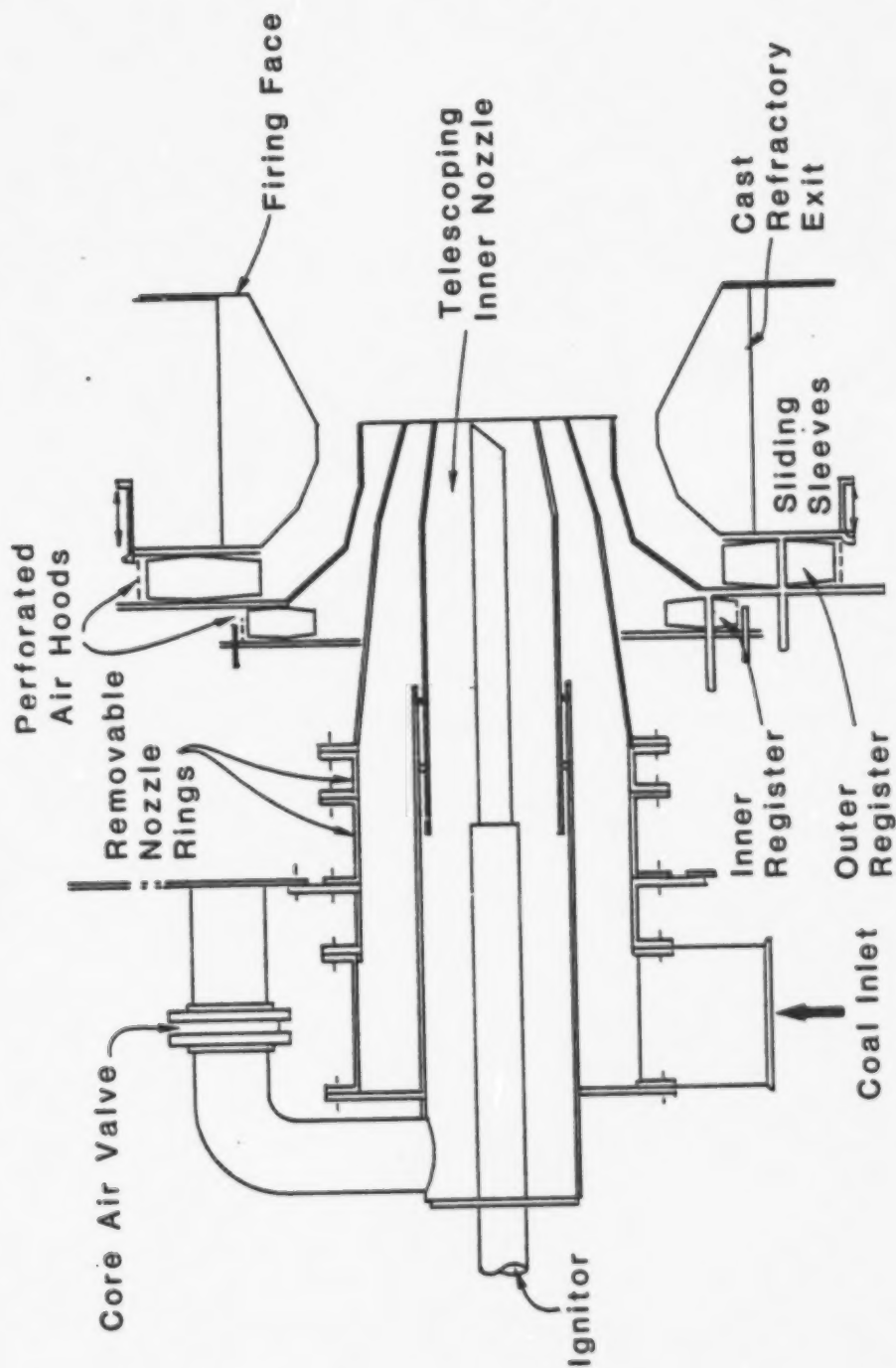


Figure 1. Initial prototype DMB using Foster Wheeler components (tertiary ports not shown).

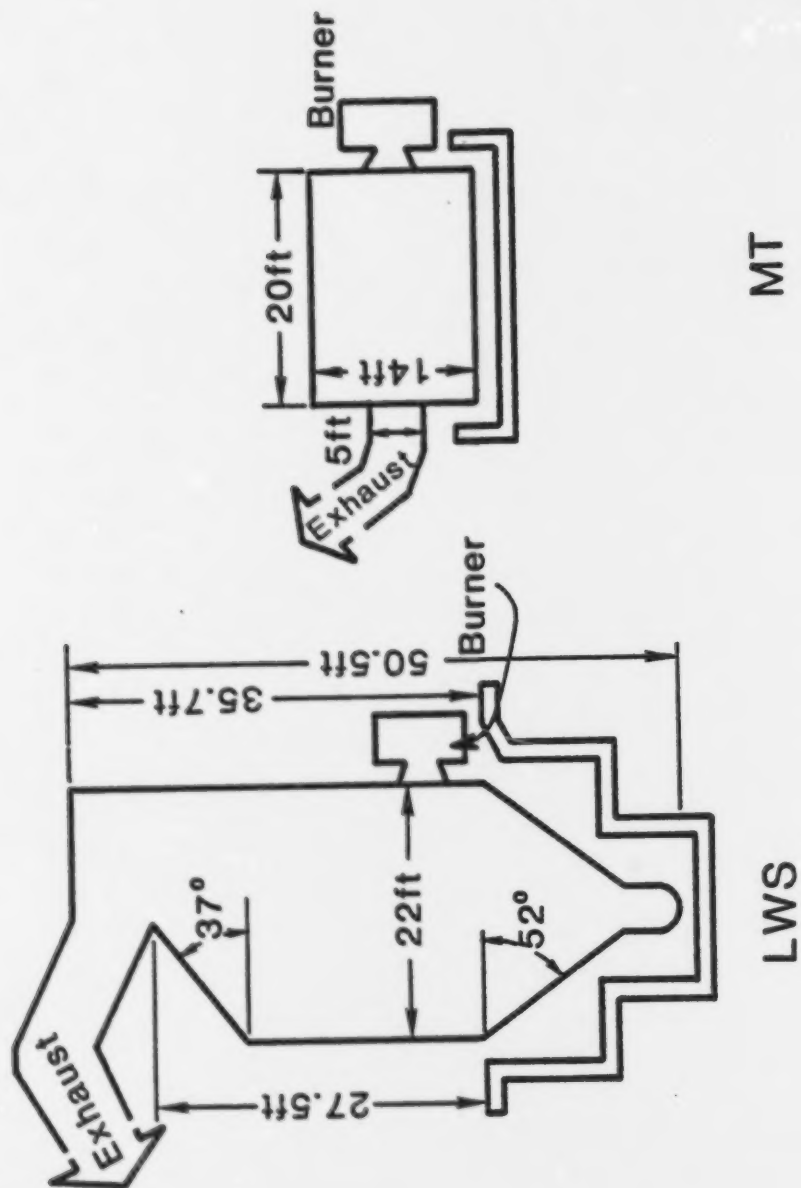


Figure 2. Test furnace geometries.

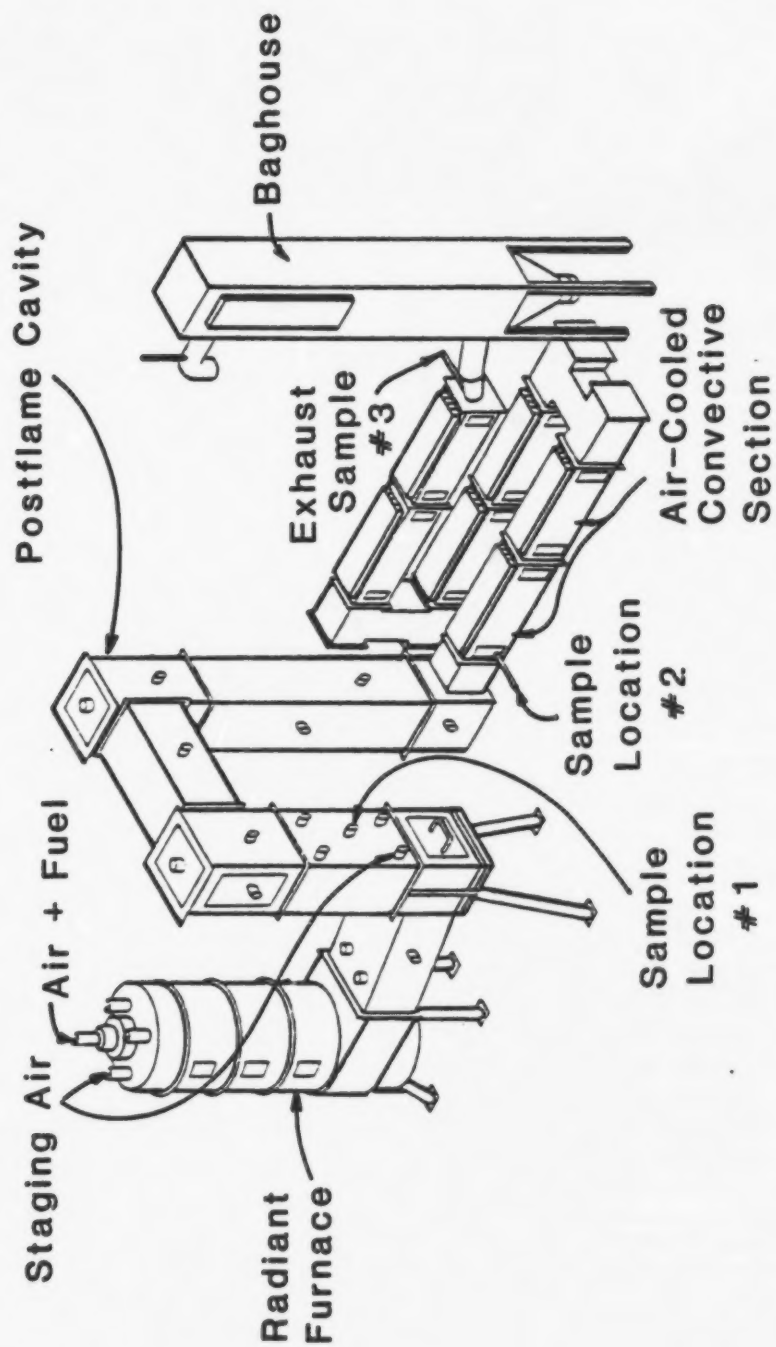


Figure 3. Bench scale test facility.

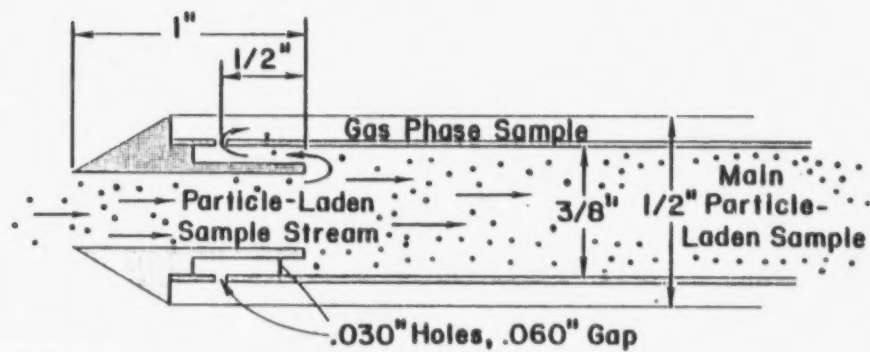
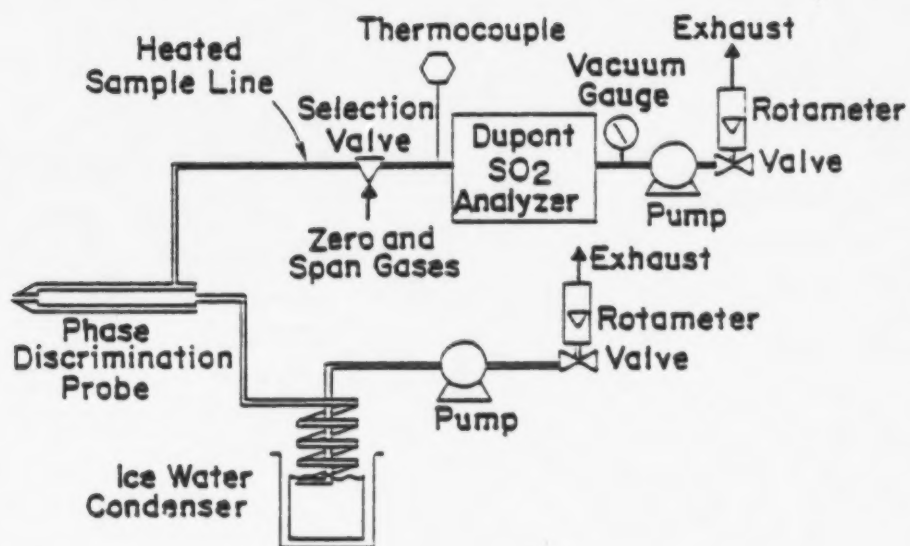


Figure 4. Schematic of the SO₂ sampling system and phase discrimination probe.

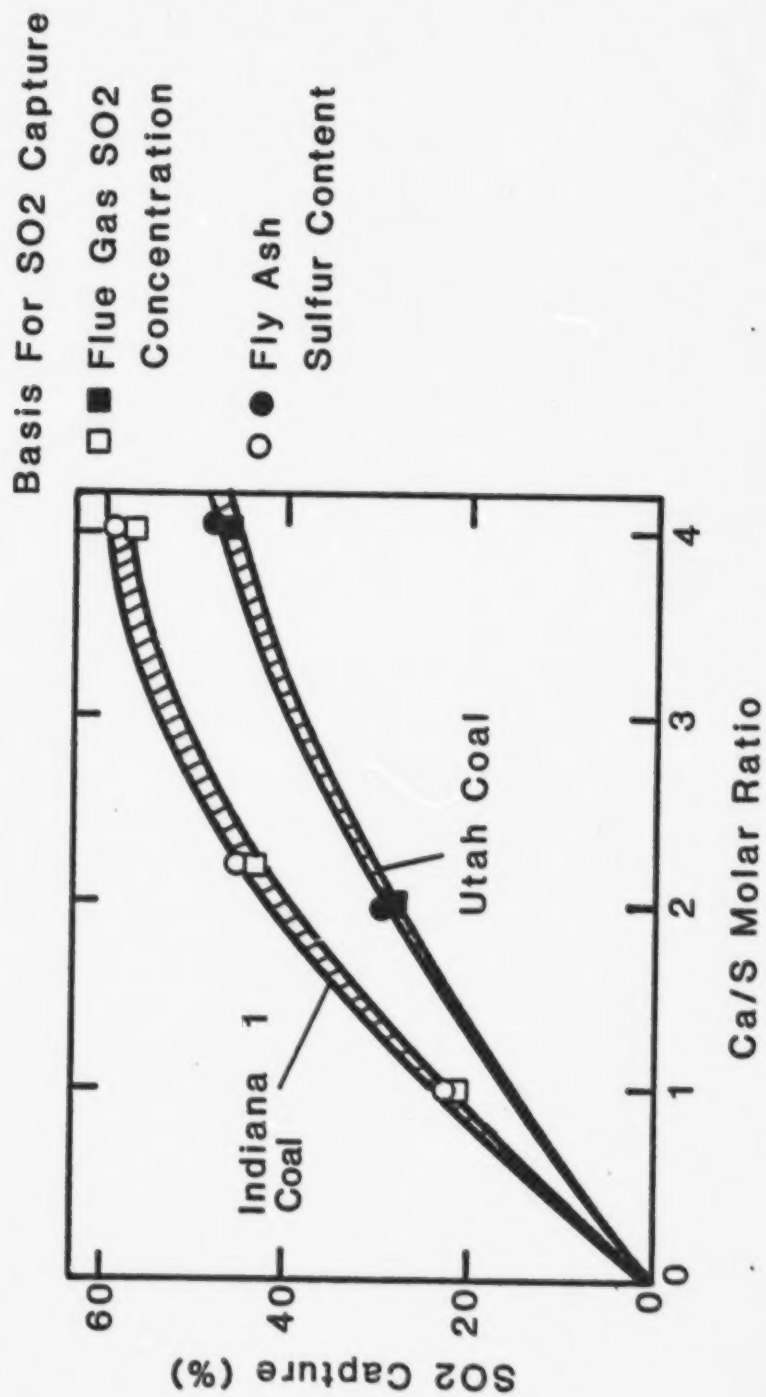


Figure 5. Determination of sulfur capture based on flue gas SO₂ concentration and fly ash sulfur content.

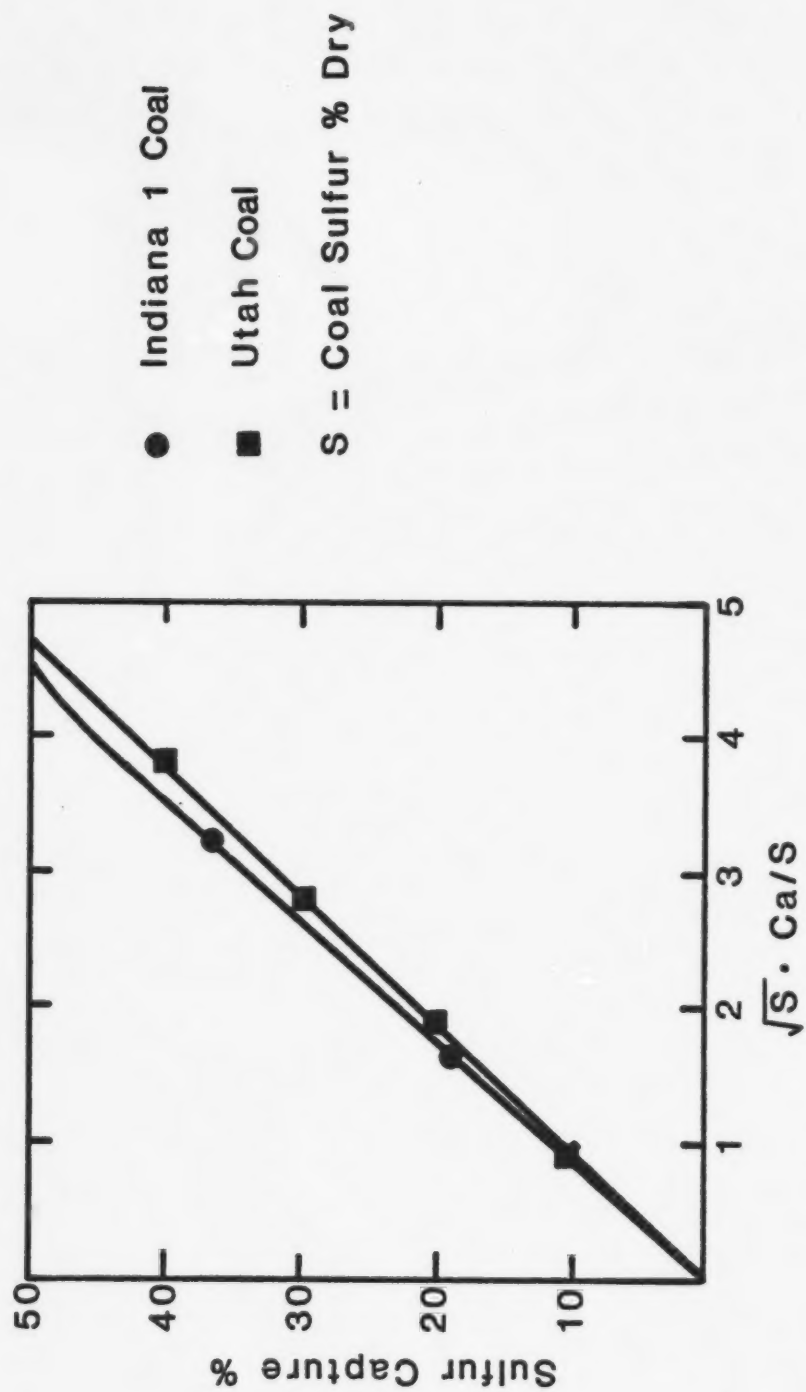


Figure 6. Correlation of sulfur capture for coals of different sulfur contents.

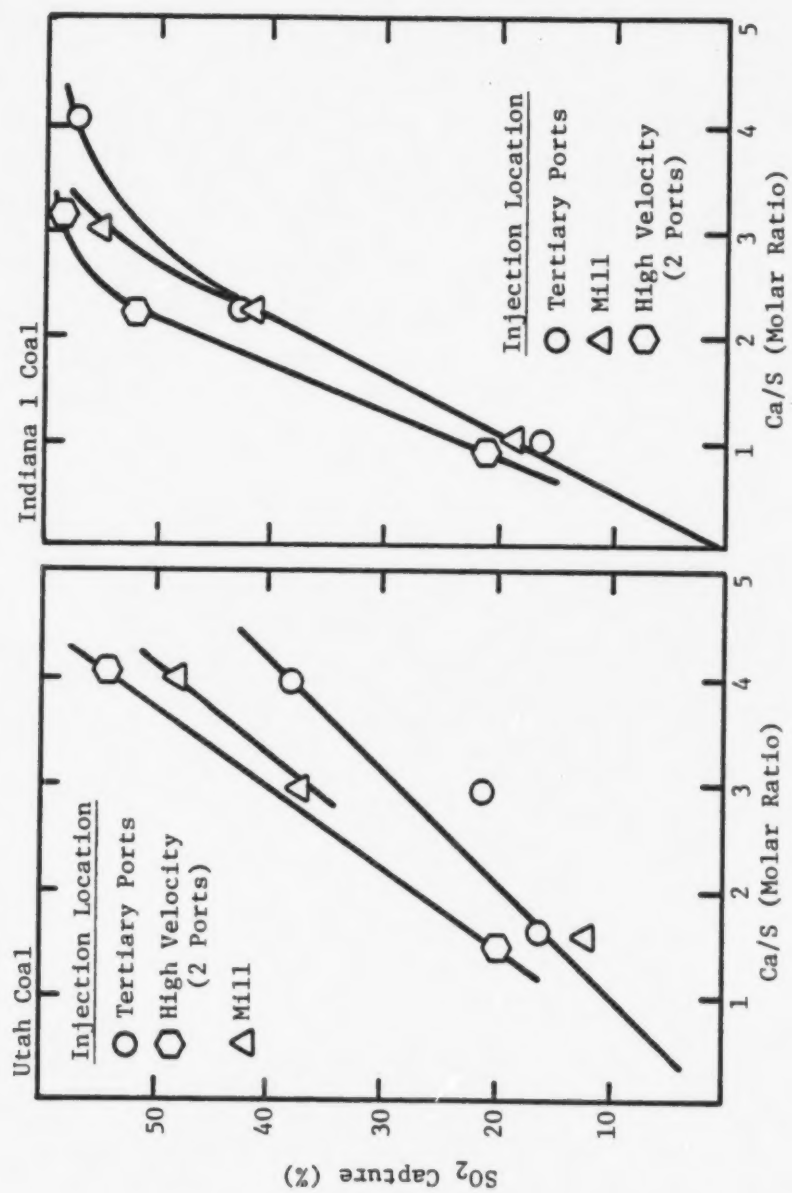


Figure 7. The impact of sorbent injection location on sulfur capture.

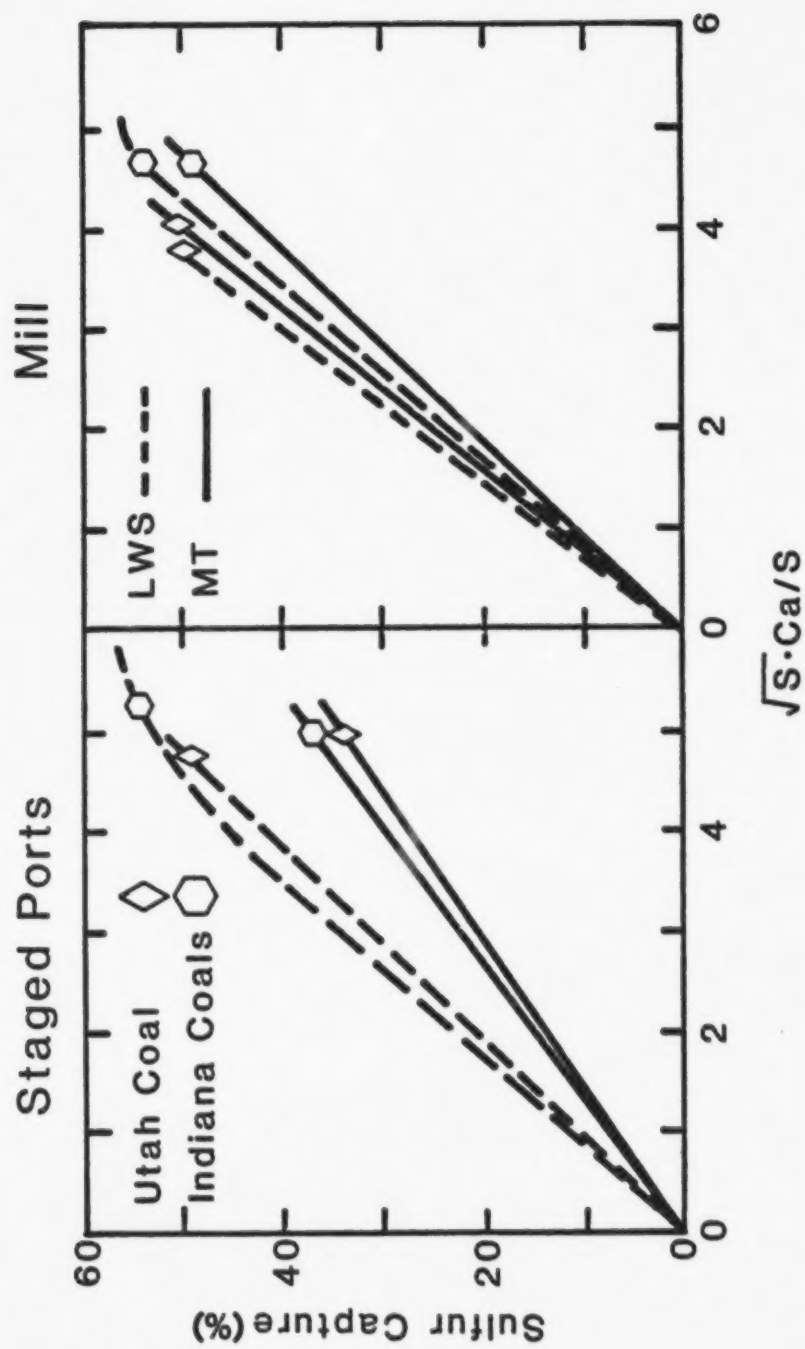


Figure 8. The influence of test combustor on sulfur capture.

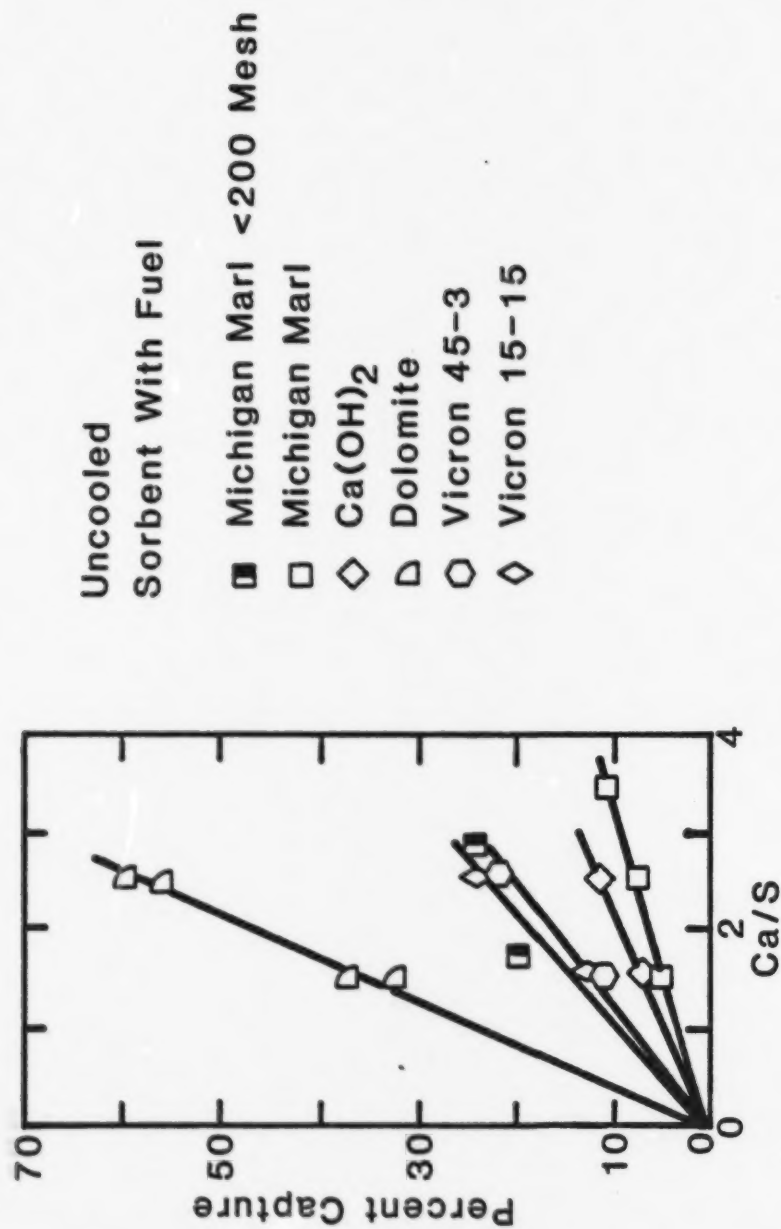


Figure 9. The influence of sorbent type on sulfur capture.

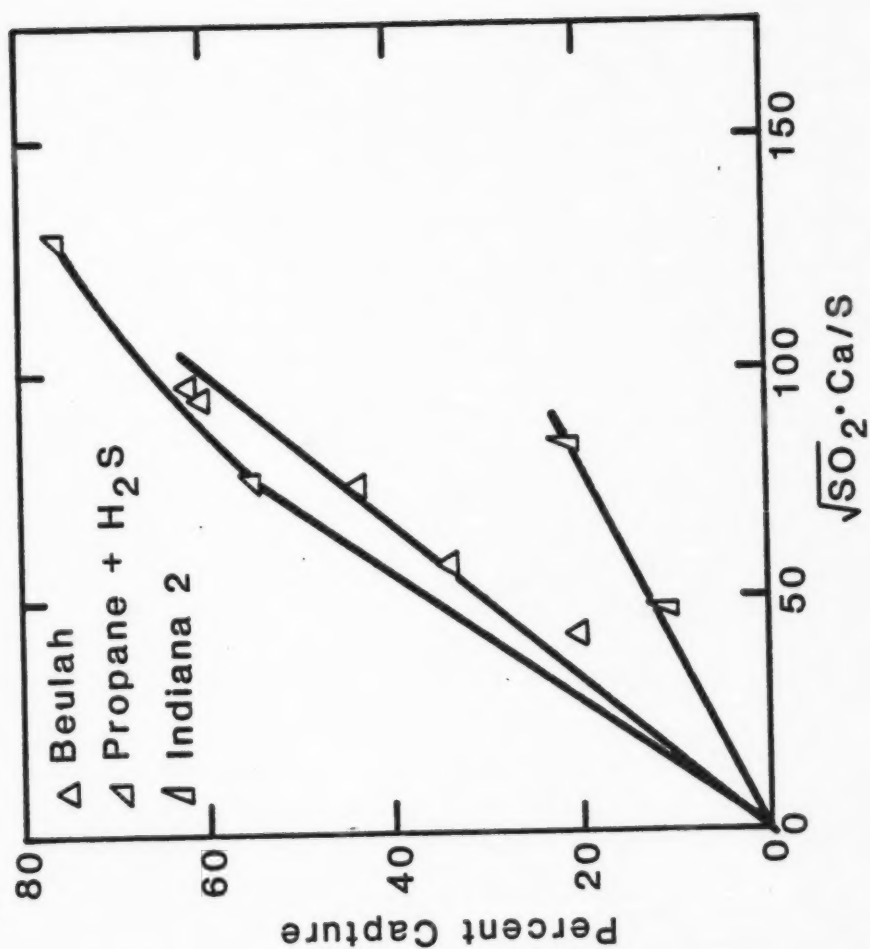


Figure 10. The influence of fuel type on sulfur capture.

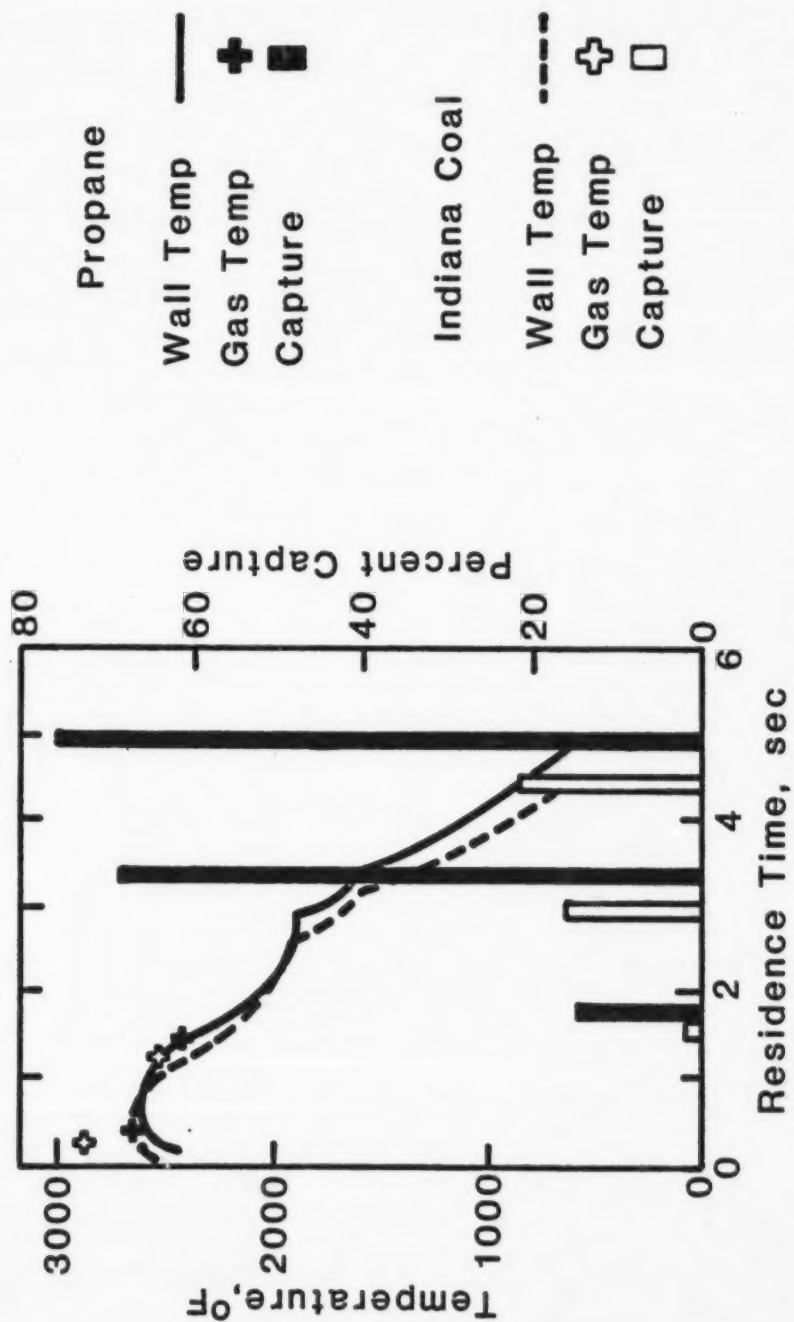


Figure 11. Sulfur capture and temperature as a function of residence time for propane doped with H_2S and Indiana coal.

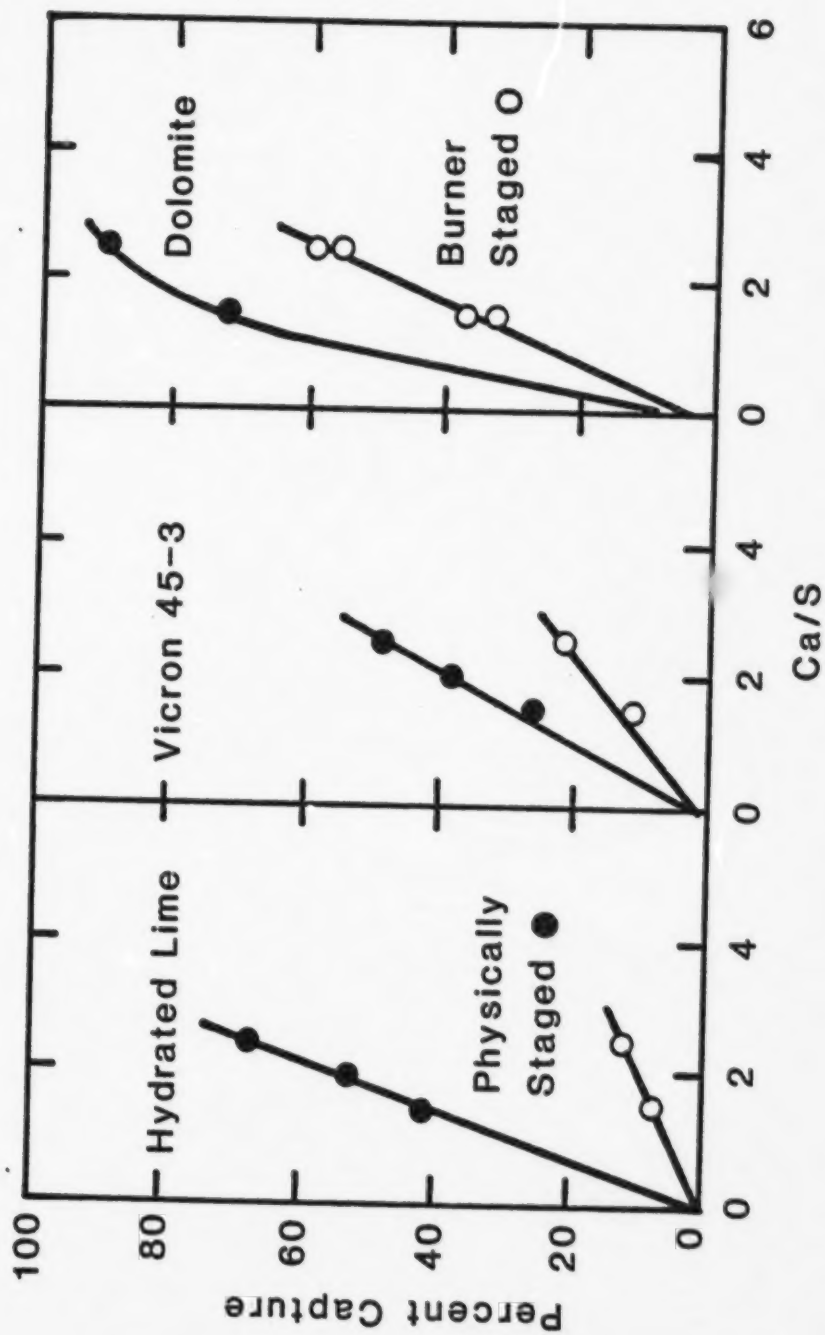


Figure 12. The impact of combustor operation on sulfur capture.

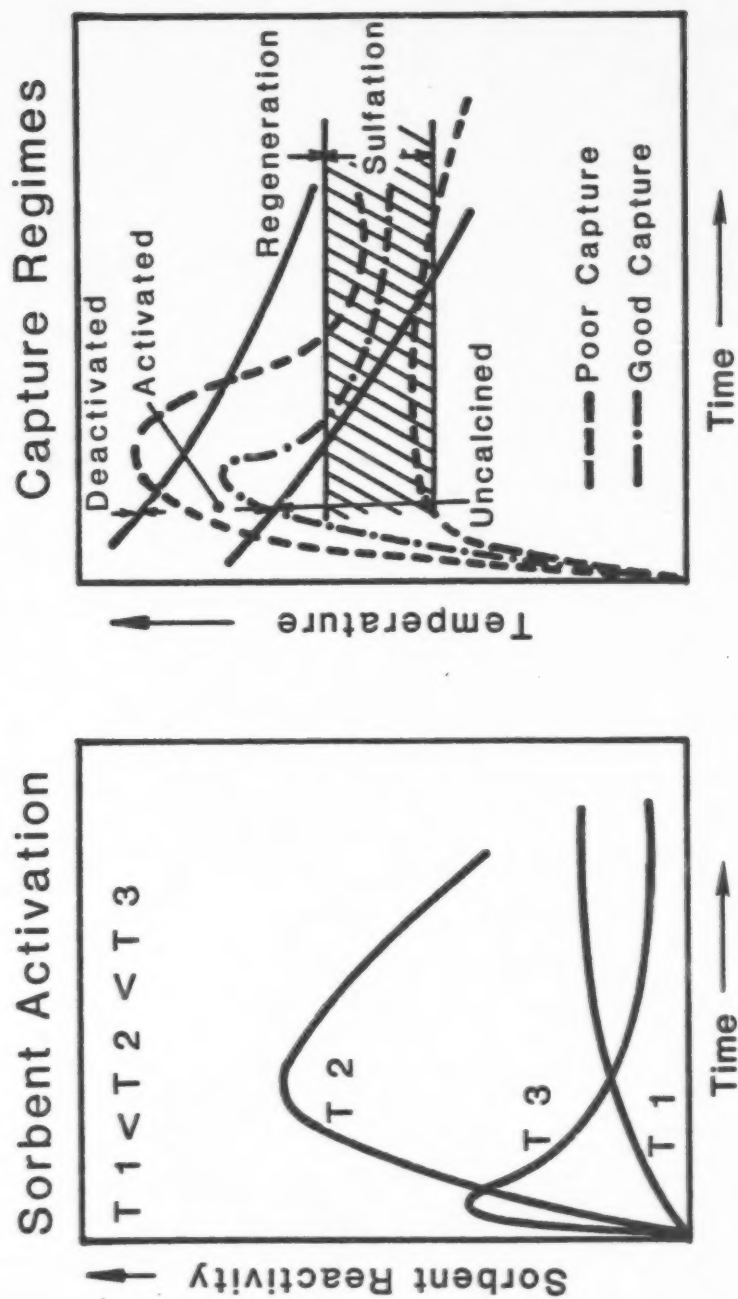


Figure 13. LIMB process description.

TABLE 1. FUEL CHARACTERISTICS

	Indiana 1	Indiana 2	Utah	Beulah
Ultimate Analysis (% Dry)				
Carbon	68.5	73.0	72.24	59.4
Hydrogen	4.9	4.8	5.75	4.6
Nitrogen	1.45	1.3	1.55	0.9
Sulfur	2.5	1.3	0.76	1.14
Oxygen	12.05	9.0	10.16	20.63
Ash	10.6	10.6	9.54	13.4
Moisture (%)	4.5	3.2	7.4	20.
Heating Value (Dry) Btu/lb	12,400	12,760	12,827	9,900
% Volatiles (Dry)	39.75	34.3	41.94	44.6
Forms of Sulfur (% Dry)				
Total	2.6	1.3	0.76	1.14
Pyritic	0.55	0.58	0.14	0.53
Organic	1.18	0.47	0.62	0.58
Sulfate	0.87	0.24	0.0	0.03

TABLE 2. SORBENT CHARACTERISTICS

Sorbent	Composition	Mean Size, μm	Form
Vicron 45-3	CaCO_3	11.0	Calcite
Vicron 15-15	CaCO_3	3.0	Calcite
Mich. Marl	CaCO_3	18.0	Marl
Mich. Marl < 200 Mesh	CaCO_3	11.0	Marl
Dolomite	$\text{CaCO}_3 \cdot \text{MgCO}_3$	34.0	
Hydrated Lime	Ca(OH)_2	12.5	

APPENDIX A
LIST OF ATTENDEES

1982 JOINT SYMPOSIUM ON STATIONARY COMBUSTION NO_x CONTROL
DALLAS, TEXAS, NOVEMBER 1-4, 1982

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